Agenda
Standards Committee Meeting

July 19, 2023 | 10:00 a.m—1:00 p.m. Central

Hybrid Meeting
Midwest Reliability Organization
380 St. Peter Street, Suite 800
St. Paul, MN 55102

SC in the Riel Room

Dial-in: 1-415-655-0002 | Access Code: 2317 037 9937 | Meeting Password: 071923
Click here to: Join WebEx

Introduction and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement*
NERC Participant Conduct Policy

Agenda Items

1. **Review July 19, 2023 Agenda - Approve - *Amy Casuscelli* (1 minute)**
2. **Consent Agenda - Approve - *Amy Casuscelli* (5 minutes)**
    a. June 21, 2023 Standards Committee Meeting Minutes* - **Approve**
3. **Projects Under Development - Review**
    a. Project Tracking Spreadsheet - *Mike Brytowski* (10 minutes)
    b. Three-month outlook* - *Latrice Harkness (5 minutes)*
    c. Projected Posting Schedule* - *Latrice Harkness* (5 minutes)
4. **Modification of MOD-031-3 Demand and Energy Data - Accept/Authorize/Authorize - *Latrice Harkness* (10 minutes)**
    a. MOD-031-3 Demand and Energy Data Standard Authorization Request*
5. **Modification of TPL-001-5.1 Transmission System Planning Performance Requirements -Accept/ Authorize/Authorize - *Jamie Calderon* (10 minutes)**
    a. TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather Standard Authorization Request*
6. **Project 2021-03 CIP-002 - Authorize - *Latrice Harkness* (10 minutes)**

7. **Project 2022-05 Modifications to CIP-008 Reporting Threshold - Accept/Appoint/Authorize - *Alison Oswald* (10 minutes)**
    a. CIP-008 Reporting Threshold Standard Authorization Request*
8. **Project 2022-04 EMT Modeling - Accept/Appoint/Authorize - *Latrice Harkness* (10 minutes)**
    a. EMT Modeling Standard Authorization Request*
9. **Project 2023-01 EOP-004 IBR Event Reporting - Authorize - *Jamie Calderon* (10 minutes)**
    a. EOP-004-5*
    b. Implementation Plan*
10. **Project 2022-01 Reporting ACE Definition and Associated Terms - Authorize - *Jamie Calderon* (10 minutes)**
    a. ACE Diversity Interchange Definition*
11. **Project 2021-04 Modifications to PRC-002 - Authorize - *Latrice Harkness* (10 minutes)**
    a. PRC-002-5*
    b. PRC-028-1*
    c. Implementation Plan*
12. **Subcommittee Updates**
    a. Project Management and Oversight Subcommittee (PMOS) - *Mike Brytowski* (10 minutes)
    b. Standards Committee Process Subcommittee (SCPS) - *Matt Harward* (10 minutes)
    c. Standing Committees Coordinating Group (SCCG) - *Todd Bennett* (10 minutes)
    d. Reliability and Security Technical Committee (RSTC) - *Venona Greaff* (10 minutes)
    e. NERC Board of Trustees - *Sue Kelly* (10 minutes)
13. **Legal Update and Upcoming Standards Filings* - Review - *Sarah Crawford* (5 minutes)**
14. **Informational Items - Enclosed**
    a. Standards Committee Expectations*
    b. 2023 SC Meeting Schedule
    c. 2023 Standards Committee Roster
    d. Highlights of Parliamentary Procedure*
15. **Adjournment**

*Background materials included.

Public Meeting Notice

REMINDER FOR USE AT BEGINNING OF MEETINGS AND CONFERENCE CALLS THAT HAVE BEEN PUBLICLY NOTICED AND ARE OPEN TO THE PUBLIC

Conference call/webinar version:

As a reminder to all participants, this webinar is public. The registration information was posted on the NERC website and widely distributed. Speakers on the call should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Face-to-face meeting version:

As a reminder to all participants, this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

For face-to-face meeting, with dial-in capability:

As a reminder to all participants, this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. The notice included the number for dial-in participation. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Minutes
Standards Committee Meeting

A. Casuscelli, chair, called to order the meeting of the Standards Committee (SC or the Committee) on June 21, 2023, at 1:00 p.m. Eastern. C. Larson called roll and determined the meeting had a quorum. The SC member attendance and proxy sheets are attached as Attachment 1.

NERC Antitrust Compliance Guidelines and Public Announcement
The Committee secretary called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice and directed questions to NERC's General Counsel, Sonia C. Rocha.

Introduction and Chair's Remarks
A. Casuscelli welcomed the Committee, guests, and proxies to the meeting.

Review June 21, 2023 Agenda (agenda item 1)
The SC approved the June 21, 2023 meeting agenda.

Consent Agenda (agenda item 2)
The Committee approved the May 17, 2023 Standards Committee Meeting Minutes, subject to correcting an error with the CIP-002 agenda item. The Committee also approved the June 2, 2023 Standards Committee Executive Committee Meeting Minutes.

Projects Under Development (agenda item 3)
M. Brytowski reviewed the Project Tracking Spreadsheet. L. Harkness reviewed the Project Posting Schedule.

Project CIP-014-3 Risk Assessment Refinement (agenda item 4)
S. Kim provided an overview of the project background and standard authorization request (SAR).
T. Pyle made a motion to accept the CIP-014-3 – Physical Security SAR submitted by the NERC technical and compliance staff, authorize posting of the SAR for a 30-day formal comment period, and authorize the solicitation of the standard drafting team (SDT) members.

The committee approved the motion with no objections or abstentions.

Project 2023-02 Performance of IBRs (agenda item 5)
S. Kim provided an overview of the recommended slate of SDT members. T. Pyle recommended Candidate #20 and Candidate #18 also be considered. J. Howell shared the recommended slate may lack Generator Owner representation. S. Kim shared the recommended slate was relatively balanced with Generator Owners, ISO, and other entities. T. Pyle made a motion to appoint chair, vice chair, and members with the addition of Candidate #20 to the Project 2023-02 Performance of Inverter-Based Resources (IBRs) Standard drafting team (SDT).

The committee approved the motion with no objections or abstentions.

Project 2023-03 Internal Network Security Monitoring (agenda item 6)
S. Kim provided an overview of the recommended slate of SDT members. C. Yeung shared that there is no Balancing Authority or Reliability Coordinator representation. C. Yeung recommended adding Additional Candidate #5. C. Yeung made a motion to appoint chair, vice chair, and members with the addition of Additional Candidate #5 to the Project 2023-03 Internal Network Security Monitoring (INSM) Standard Drafting Team (SDT)

The committee approved the motion with no objections or abstentions.

Project 2023-04 Modifications to CIP-003 (agenda item 7)
S. Kim provided an overview of the recommended slate of SDT members. V. Greaff made a motion to appoint chair, vice chair, and members to the Project 2023-04 Modifications to CIP-003 standard drafting team (SDT), as recommended by NERC staff.

The committee approved the motion with no objections or abstentions.

Standard Processes Manual (agenda item 8)
S. Crawford, NERC Legal, provided an update on the SPM revisions.

Legal Update and Upcoming Standards Filings (agenda item 9)
S. Crawford provided an update.

Adjournment
The meeting adjourned at 1:48 p.m. Eastern.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Committee 2023 Segment Representatives

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Chair 2022-23	Amy Casuscelli* Manager, Reliability Assurance & Risk Management	Xcel Energy		Yes
Vice Chair 2022-23	Todd Bennett* Managing Director, Reliability Compliance & Audit Services	Associated Electric Cooperative, Inc.		Yes
Segment 1-2022-23	Michael Jones Manager, Reliability Standards & Policy	National Grid		Yes
Segment 1-2021-22	Troy Brumfield* Regulatory Compliance Manager	American Transmission Company		Yes
Segment 2-2022-23	Jamie Johnson Infrastructure Compliance Manager	California ISO		Yes
Segment 2-2021-22	Charles Yeung Executive Director Interregional Affairs	Southwest Power Pool		Yes
Segment 3-2022-23	Kent Feliks Manager NERC Reliability Assurance – Strategic Initiatives	American Electric Power Company, Inc.		Yes
Segment 3-2021-22	Vicki O' Leary Director – Reliability, Compliance, and Implementation	Eversource Energy		Yes
Segment 4-2022-23	Marty Hostler Reliability Compliance Manager	Northern California Power Agency		Yes
Segment 4-2021-22	Patti Metro Senior Grid Operations & Reliability Director	National Rural Electric Cooperative Associate		No
Segment 5-2022-23	Terri Pyle Utility Operational Compliance and NERC Compliance Office	Oklahoma Gas and Electric		Yes
Segment 5-2021-22	Jim Howell Markets Compliance Manager	Southern Company Generation		Yes

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Segment 6-2022-23	Sarah Snow* Manager of Reliability Compliance	Cooperative Energy		No
Segment 6-2021-22	Justin Welty Senior Manager, NERC Reliability Standards	NextEra Energy		Yes
Segment 7-2022-23	Kristine Martz Industry Specialist, Power & Utilities	Amazon Web Services	Maggy Powell	Yes
Segment 7-2021-22	Venona Greaff* Senior Energy Analyst	Occidental Chemical Corporation		Yes
Segment 8-2022-23	Robert Blohm[1] Managing Director	Keen Resources Ltd.		No
Segment 8-2021-22	Philip Winston Retired (Southern Company)	Independent		No
Segment 9-2022-23	Sarosh Muncherji[1] Cyber Security Specialist	British Columbia Utilities Commission		Yes
Segment 9-2021-22	William Chambliss General Counsel	Virginia State Corporation Commission		Yes
Segment 10-2022-23	Tony Purgar Senior Manager, Operational Analysis & Awareness	ReliabilityFirst		Yes
Segment 10-2021-22	Steven Rueckert Director of Standards	WECC		Yes

[1] Serving as Canadian Representative
*Denotes SC Executive Committee Member

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

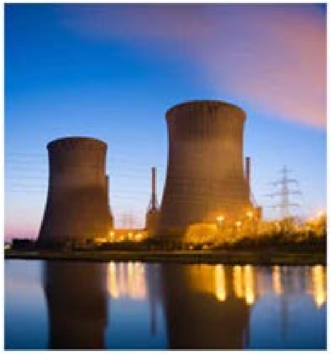
Agenda Item 3b
Standards Committee
July 19, 2023

Three-Month Outlook

Third Quarter 2023

Latrice Harkness, Director, Standards Development, NERC
Standards Committee
July 19, 2023

RELIABILITY | RESILIENCE | SECURITY

Standard Authorization Request Actions

- July
  - Modification of MOD-031-3 Demand and Energy Data
  - Modification of TPL-001-5.1 Transmission System Planning Performance Requirements
  - Project 2022-05 CIP-008 Reporting Thresholds
  - Project 2022-04 EMT Modeling
- August
  - Project 2023-04 CIP-003
  - Project 2023-03 Internal Network Security Monitoring
- September
  - Project 2023-02 Performance of IBRs

Authorize Nomination Solicitations

- July
  - Modification of MOD-031-3 Demand and Energy Data
  - Modification of TPL-001-5.1 Transmission System Planning Performance Requirements
  - Project 2021-03 CIP-002
- August
  - None
- September
  - None

Appoint Drafting Teams

- July
  - Project 2022-05 Modifications to CIP-008 Reporting Threshold (SAR DT to SDT)
  - Project 2022-04 EMT Modeling (SAR DT to SDT)
- August
  - None
- September
  - Modification of MOD-031-3 Demand and Energy Data
  - Modification of TPL-001-5.1 Transmission System Planning Performance Requirements

Authorize Initial Postings

- July
  - Project 2023-01 EOP-004 IBR Event Reporting
  - Project 2022-01 Reporting ACE Definition and Associated Terms
  - Project 2021-04 Modifications to PRC-002-4
- August
  - Project 2021-08 FAC-008
- September
  - Project 2023-03 Internal Network Security Monitoring

Questions and Answers

Modification of MOD-031-3 — Demand and Energy Data

Action

- Accept the MOD-031-3[1] Standard Authorization Request (SAR) submitted by the NERC System Performance Impact of Distributed Energy Resources Working Group (SPIDERWG) and endorsed by the Reliability and Security Technical Committee (RSTC) on June 21, 2023;
- Authorize posting of the SAR for a 30-day informal comment period; and
- Authorize solicitation of the drafting team (DT) members.

Background

The NERC Reliability Standard MOD-031-3 seeks to "provide authority for applicable entities to collect Demand energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data." The SPIDERWG has recently recommended in the *White Paper: SPIDERWG NERC Reliability Standards Review*[2] that MOD-031-3 should be revised to allow for the Planning Coordinator (PC) to obtain existing and forecasted distributed energy resource (DER) information from Distribution Provider (DP) and Transmission Planner (TP) entities. The White Paper further asserts that the TP should have the ability to act as an intermediary to provide data from DPs to the PC.

The intent of this SAR is to revise and modify MOD-031-3 in the "Requirements and Measurements" section so that PCs are allowed to obtain existing and forecasted DER information from DPs or TPs. This project's goal is to ensure that various forms of historical and forecast Demand, energy data, and information are available to the parties that perform reliability studies and assessments and provide the authority needed to collect the applicable data.

Summary

NERC staff recommends that the SC accept the MOD-031-3 SAR, authorize posting of the SAR for a 30-day informal comment period; and authorize solicitation of the DT members.

[1] See MOD-031-3 at https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-031-3.pdf.
[2] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	MOD-031-3 — Demand and Energy Data		
Date Submitted:	06/27/2023		
SAR Requester			
Name:	Shayan Rizvi, NPCC (NERC SPIDERWG Chair) John Schmall , ERCOT (NERC SPIDERWG Vice-Chair)		
Organization:	The NERC System Planning Impacts of DER Working Group (SPIDERWG)		
Telephone:	Shayan – 212-840-1070 John – 512-248-4243	Email:	Shayan – srizvi@nppc.org John – john.schmall@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
MOD-031-3 seeks to "provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data." The SPIDERWG has recently recommended in the *White Paper: SPIDERWG NERC Reliability Standards Review*[1] that MOD-031-3 should be revised to allow for the PC to obtain existing and forecasted DER information from DPs or TPs. The TP should have the ability to act as an intermediary to provide data from DPs to the PC.			

[1] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf

Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this SAR is to revise and modify MOD-031-3 in the "Requirements and Measurements" section so that PC are allowed to obtain existing and forecasted DER information from DPs or TPs. This project's goal is to ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, and provide the authority needed to collect the applicable data.
Project Scope (Define the parameters of the proposed project):
SPIDERWG recommends that a Standard Drafting Team (SDT) review and modify MOD-031-3, as necessary, such that the Standard requires DPs and TPs to provide existing and forecasted DER data when the PC determines the need as it is becoming critical to know how much actual demand is on the system given the amount being served by embedded generation..
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[2] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
SPIDERWG identified that standards revisions be made to MOD-031 to have specific language reflecting DERs[3] and how to address them. TPs should be an intermediary to provide this data from DPs to the PC as the DER from the DP affects the existing and forecasted demand amount of the TP's planning area as well as the TP's projected DER capacity for their planning area. This process continues up for each TP in a PC's planning area. Thus, to minimize double counting, the TPs should be the intermediary of DER forecast information between DPs and PCs. Because of how each entity's forecast is dependent on the results of another, the standard should be both clear on DER and revised to ensure the PC's need to obtain existing and forecasted gross demand is met. This process is currently not found in MOD-031-3 language and would add a separate pathway of data transfer specific to DER data. The current structure of MOD-031 has a PC request information of entities, and this change would have the TP act as an intermediary to the DP for PC requests for existing and forecasted DER capacity information. As no reporting mechanism currently exists for DER resource owners to identify their future year interconnection date to the DP, the SDT should ensure provisions are available to DPs to share

[2] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[3] MOD-031 calls out "Demand-side Management" whose definition is "All activities or programs undertaken by any applicable entity to achieve a reduction in Demand." A reading of this definition includes generation sources as they offset Demand, or "the rate at which electric energy is delivered to or by a system or part of a system." The SPIDERWG review of this standard calls for greater specificity to be added to this standard.

Requested information
narrative and data projections appropriate to the data they have available. This existing and future projections is separate from the details for steady-state and stability data specifications per MOD-032-1, which is currently in update by Project 2022-02. For instance, the "monthly peak hour forecast" for DER will have a maximum active power value for the entity's footprint, but this does not equate to the equipment active power settings covered by Project 2022-02.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The costs are unknown. Potentially, there will be a staffing increase to perform the forecasting; however, that cost can be on the transmission entity side of this SAR.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR specifies the addition of requirements to data exchange between PCs, TPs and DPs in addition to TPs being the intermediary between DPs and the PC. This should not have a negative impact BES facilities.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Impacted: Planning Coordinator (PC), Transmission Planner (TP), Balancing Authority (BA), Resource Planner, and Distribution Providers (DP)
Do you know of any consensus building activities[4] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR has been submitted through the RSTC and has been vetted by the SPIDERWG membership. The SPIDERWG also coordinated with the Reliability Assessment Subcommittee under the RSTC as MOD-031 impacts their ability to perform assessments. Their review is incorporated in the scoping sections of this SAR. The SPIDERWG membership includes BAs, RCs, TOs, TPs, TOPs, PCs, and DPs. The SPIDERWG recommended this standard be revised in *White Paper: SPIDERWG NERC Reliability Standards Review*.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?

[4] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information
Project 2022-02 is currently defining DER, which can be used in this standard for current and projected capacity information under MOD-031. As Project 2022-02[5] is currently defining the term "DER", the SDT should define the term "DER" in the NERC Glossary of Terms if Project 2022-02 does not produce a term in the NERC Glossary of Terms as part of its final project Project 2022-02 covers the steady-state and dynamics data requirements pertaining to DERs, while this SAR is proposing a project to cover current and forecasted capacity projections for DERs. This SAR does not propose to link the two outside of using common definitions in the NERC Glossary of Terms for DERs.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The SPIDERWG considered Standards revisions alongside compliance implementation guidance and reliability guidelines. Neither compliance implementation guidance nor reliability guidelines were determined to be sufficient by SPIDERWG in their consensus-based white paper above.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.

[5] Project Page available here: https://www.nerc.com/pa/Stand/Pages/Project2022-02ModificationstoTPL-001-5-1andMOD-032-1.aspx

Reliability Principles	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following [Market Interface Principles]?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	N/A

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Modification of TPL-001-5.1 – Transmission System Planning Performance Requirements

Action

- Accept the TPL-001-5.1[1] Standard Authorization Request (SAR) submitted by the NERC staff in response to FERC Order No. 896,[2] issued June 2023;
- Authorize posting of the SAR for a 45-day informal comment period; and
- Authorize solicitation of the drafting team (DT) members.

Background

At its June 2023 open meeting, Federal Energy Regulatory Commission (FERC) issued Order No. 896 directing NERC to submit a new or revised Reliability Standard that better accounts for the effects of extreme heat and cold in long-term transmission planning.

In so directing, FERC found that the current transmission planning Reliability Standard, TPL-001-5.1, does not obligate Transmission Planners and Planning Coordinators to consider extreme hot and cold weather in their transmission planning assessments. In particular, Table 1 of the standard, provisions 2.f (stability) and 3.b (steady state) require stability and steady state analyses, respectively, to be performed for certain traditional extreme events, but do not require it for extreme heat and cold conditions.

FERC also noted the extreme weather-related events that have spanned the continent in recent years demonstrate the challenges associated with planning for extreme heat and cold weather events, particularly in unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future.

In its order, FERC found that planners need to define benchmark extreme heat and cold weather events, develop planning cases with appropriate sensitivities over a wide area, and implement corrective actions where system performance is not met, including appropriate coordination and communication of studies. NERC must submit a new or modified transmission planning Reliability Standard consistent with the directives in Order No. 896 by December 2024.

Summary

In Order No. 896, FERC directed NERC to address the reliability gap pertaining to the consideration of extreme heat and cold weather events that exist in current transmission planning standard TPL-001-5.1. NERC was directed to develop a new or modified Reliability Standard that requires the following: (1) the development of benchmark planning cases based on information such as major prior extreme heat and cold weather events and/or future

[1] See TPL-001-5.1 at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.1.pdf.
[2] Order No. 896, *Transmission System Planning Performance Requirements for Extreme* Weather, 183 FERC ¶ 61,191 (Jun. 15, 2023), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230615-3100&optimized=false. The final rule was published in the Federal Register on June 23, 2023. *See* https://www.federalregister.gov/documents/2023/06/23/2023-13286/transmission-system-planning-performance-requirements-for-extreme-weather.

meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios, including expected availability of the resource mix during extreme heat and cold weather conditions, including the broad area impacts of extreme heat and cold weather; and (3) the development of corrective action plans that mitigate specified instances where performance requirements during extreme heat and cold weather events are not met.

The SAR contains additional information and guidance from Order No. 896, including topics for consideration by the drafting team in developing a responsive standard.

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Transmission System Planning Performance Requirements for Extreme Weather		
Date Submitted:	July 5, 2023		
SAR Requester			
Name:	Mohammed Osman, Lead Engineer of System Analysis, Power System Analysis William Lamanna, Senior Engineer – Reliability Assessments Scott Barfield-McGinnis, Principal Technical Advisor, Power Risk Issues and Strategic Management		
Organization:	NERC		
Telephone:	Mohamed: 404-446-9634 Scott: 404-446-9689 William: 404-446-2568	Email:	Mohamed.Osman@nerc.net Scott.Barfield@nerc.net William.Lamanna@nerc.net
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The current transmission planning Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements[1] does not expressly require transmission planners and planning coordinators to consider extreme hot and cold weather in their transmission planning assessments. In particular, Reliability Standard TPL–001–5.1, Table 1, provisions 2.f (stability) and 3.b (steady state)			

[1] TPL-001-5.1 at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.1.pdf.

Requested information
require stability and steady state analyses, respectively, to be performed for certain traditional extreme events, but does not expressly require them for extreme heat and cold conditions. Extreme weather-related events that have spanned the continent in recent years demonstrate the challenges associated with planning for extreme heat and cold weather events, particularly those events that affect a wide area or that occur during periods when the Bulk-Power System (BPS) must meet unexpected high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. At the same time, the changing resource mix has resulted in a grid that is increasingly more susceptible to the impacts of extreme heat and cold weather events. Recent extreme weather events have shown the risk that such events can pose to the reliable operation of the BPS, and have highlighted the high risk to life and extreme economic impacts that can result from unplanned load shed during such conditions. Long-term transmission planning, along with other measures, can play an important role in identifying and helping to minimize these risks. Accordingly, this project will revise the NERC transmission planning Reliability Standards, consistent with FERC Order No. 896,[2] to address the study of extreme heat and cold conditions. The impact of concurrent failures of BPS generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented. These standard(s) should use benchmark extreme heat and cold weather events for the required studies, and require the development of planning cases with appropriate sensitivities over a wide-area. The standard should also require the identification and implementation of corrective actions where system performance requirements are not met, including appropriate coordination and communication of studies.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Consistent with FERC Order No. 896, this purpose of this project is to address the reliability gap pertaining to the consideration of extreme heat and cold weather events that exist in current transmission planning standards (e.g., NERC Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements). In Order No. 896, NERC was directed to develop a new or modified Reliability Standard ("Standard") that requires the following: (1) the development of benchmark planning cases based on information such as major prior extreme heat and cold weather events and/or future meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios, including expected availability of the resource mix during extreme heat and cold weather conditions, and including the broad area impacts of extreme

[2] Order No. 896, *Transmission System Planning Performance Requirements for Extreme Weather*, 183 FERC ¶ 61,191 (2023), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230615-3100&optimized=false.

Requested information
heat and cold weather; and (3) the development of corrective action plans that mitigate specified instances where performance requirements during extreme heat and cold weather events are not met.
Project Scope (Define the parameters of the proposed project):
The scope of the proposed project is to develop a new transmission planning Standard, or modify an existing Standard, to address the directives from FERC Order No. 896 pertaining to the study of extreme heat and cold events. New or revised definitions may be required. This project may also need to revise Standard MOD-032-1 – Data for Power System Modeling and Analysis[3] for data sharing.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The drafting team is responsible for the development of new Standard or the revision of Standard TPL-001-5.1 that shall achieve the actions listed below related to addressing concerns pertaining to transmission system planning for extreme heat and cold weather events outlined in the Order that impact the Reliable Operation of the Bulk-Power System. The technical justification of the reliability-related benefits of developing a new Standard, modified Standard, or industry definition were addressed in the NOPR[5] and Order. The following actions have been listed in a sequence consistent with the directives in the Order. **A. Develop New or Modified Standard** Develop a new or modified Standard[6] to require the following:[7] 1. Development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; 2. Planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and

[3] See MOD-032-1 at https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-032-1.pdf.
[4] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
[5] See Docket RM22-10-000, NOPR 179 FERC ¶ 61,195, document number 2022-13471 at https://www.federalregister.gov/documents/2022/06/27/2022-13471/transmission-system-planning-performance-requirements-for-extreme-weather.
[6] Order at P25.
[7] Order at P27.

Requested information
3. Development of corrective action plans that mitigate specified instances where performance requirements for extreme heat and cold weather events are not met.[8] Also, identify the responsible entities for developing benchmark planning cases and conducting wide-area studies. **B. Develop Benchmark Events and Planning Cases Based on Major Prior Extreme Heat and Cold Weather Events and/or Meteorological Projections** The drafting team must consider approaches that would provide a uniform framework for developing benchmark events while still recognizing regional differences. For example, consider defining benchmark events around: • a projected frequency (e.g., 1-in-50-year event); or • a probability distribution (95th percentile event). Although the NOPR did not specify how these benchmark events should be developed, the NOPR provided two examples: (1) the drafting team could develop the benchmark event or events during the standard development process; or (2) the drafting team could include in the new or modified Standard a framework establishing a common design basis for the development of benchmark events. In developing a new of modified Standard, responsible entities are to be required to:[57] 1. Develop extreme heat and cold weather benchmark events;[9] 2. Develop benchmark planning cases based on identified benchmark events; and 3. Describe/define the types of heat and cold scenarios/events that responsible entities must study.[10] For instance, a benchmark event could be constructed based on data from a major prior extreme heat or cold event, with adjustments if necessary to account for the fact that future meteorological projections may estimate that similar events in the future are likely to be more extreme.[11] The drafting must consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution).[12] The drafting must ensure that benchmark events that all responsible entities likely to be impacted by the same extreme weather events use consistent benchmark events. Doing so is important to ensuring that neighboring planning regions are assuming similar weather conditions and are able to coordinate

[8] NOPR, 179 FERC ¶ 61,195 at P 51.
[9] Benchmark events will form the basis for a planner's benchmark planning case— i.e., the base case representing system conditions under the relevant benchmark event—that will be used to study the potential wide-area impacts of anticipated extreme heat and cold weather events.
[10] Order at P35.
[11] NOPR, 179 FERC ¶ 61,195 at P47.
[12] Order at P36.

Requested information
their assumptions accordingly. Allowing responsible entities significant discretion to determine the applicable meteorological conditions would not meet the objectives of the Order.[13] Extreme heat and cold benchmark events must reflect regional differences in climate and weather patterns.[14] The drafting team may and is encouraged to engage the national labs, RTOs, NOAA, and other agencies and organizations in developing benchmark events.[15] To provide for a common design basis for responsible entities to follow when creating benchmark planning cases, case are to represent:[16] 1. Potential weather-related contingencies (*e.g.,* concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load: 2. Transfers; 3. Generation resource mix; and 4. Impacts on generators sensitive to extreme heat or cold (due to the weather conditions indicated in the benchmark events). The drafting team must ensure the new or modified Standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data. A mechanism to update the benchmark event at least every five years would strike a reasonable balance between the benefits of using the most up-to-date meteorological data and administrative the burdens of collecting and analyzing such data.[17] **C. Defining "Wide-Area"** The drafting team in developing a new or modified Standard must include that transmission planning studies consider the wide-area impacts of extreme heat and cold weather.[18] The drafting team should consider approaches in defining "wide-area" over a geographical area consistent with weather and electrically, and how these two approaches correlate.[19] The drafting team must clearly describe the process that a responsible entity must use to define the wide-area boundaries.[20]

[13] Order at P37.
[14] Order at P38.
[15] Order at P37.
[16] Order at P39.
[17] Order at P40.
[18] Order at P41.
[19] Order at P47.
[20] Order at P50.

D. Entities Responsible for Developing Benchmark Events and Planning Cases, and for Conducting Transmission Planning Studies of Wide-Area Events

a. Entity Responsible for Establishing Benchmark Events

The Order directed NERC to develop requirements that address the types of extreme heat and cold weather scenarios responsible entities are required to study, including the development of benchmark events and benchmark planning cases.

The drafting team shall develop the new or modified Standard consistent with the approach the Commission took in Order No. 779 (i.e., TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events). Also, define mechanisms to periodically update extreme heat and cold weather benchmark events.[21]

The drafting team may use an existing functional entity or a group of functional entities (e.g., a group of planning coordinators) to designate the tasks of developing benchmark planning cases and conducting wide-area studies.[22]

b. Entities Responsible for Development of Planning Cases and Conducting Transmission Planning Studies of Wide-Area Events

The drafting team is to (1) designate the responsible entities responsible for developing benchmark planning cases, and (2) specify which responsible entities have an obligation to conduct wide-area studies under the new or modified Standard.[23]

The drafting team may designate the tasks of developing benchmark planning cases and conducting wide-area studies to an existing functional entity or a group of functional entities (*e.g.,* a group of planning coordinators). If needed, the drafting team may propose to establish a new functional entity registration to undertake these tasks by working with NERC registration and legal staffs. The drafting team, if considering such an approach, will need to consider that a new functional registration will require a modification to the NERC Rules of Procedure, which can take additional time to complete.[24]

E. Coordination Among Registered Entities and Sharing of Data and Study

In determining the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, the drafting team must ensure there is a mechanism is place to ensure the sharing of data and studies. For example, it is possible that the selected responsible entities under the new or modified Standard will not be able to request and receive needed data pursuant to MOD–032–1, absent modification to that Standard.[25]

The drafting team must require system information and study results sharing and coordination among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners for extreme heat and cold weather events.[26]

The drafting team must address wide-area coordination among giving due consideration to relevant factors identified by commenters in the Order and NOPR[27,28] At a minimum, the drafting team must require responsible entities to share the results of their wide-area studies with other registered entities

Requested information
consistent with TPL-00-1-5.1 (e.g., transmission operators, transmission owners, and generator owners that have a reliability related need for the studies).[29] **F. Concurrent/Correlated Generator and Transmission Outages** The drafting team must require the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below. Previous extreme weather events have demonstrated that there is a high correlation between generator outages and cold temperatures, indicating that as temperatures decrease, unplanned generator outages and derates increase. Because of this correlation, it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events. Some generators may be unavailable under extreme heat or cold conditions and thus their potential outages must be considered in extreme heat and cold weather planning scenarios. The drafting team may strike a balance between allowing responsible entities discretion to ensure the study incorporates their operating experience and the need to create a robust framework that ensures extreme heat and cold events are adequately studied.[30] **G. Conduct Transmission System Planning Studies for Extreme Heat and Cold Weather Events** **1. Steady State and Transient Stability Analyses** In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and cascading failures in both the steady state and the transient stability realms. The drafting team must require that responsible entities: 1. Perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies (in the long-term planning horizon[31]);

[21] Order at P59. See also Order No. 779 at https://www.federalregister.gov/documents/2016/09/30/2016-23441/reliability-standard-for-transmission-system-planned-performance-for-geomagnetic-disturbance-events.
[22] Order at P62.
[23] Order at P60.
[24] Order at P62.
[25] Order at P73.
[26] Order at P65.
[27] See Appendix A, P81 and P82 for additional information.
[28] See Appendix B, P57, P64, and P70.
[29] Order at P77.
[30] Order at P88 through P91.
[31] Order at P95.

Requested information
2. Define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Standard; 3. Develop specific criteria for determining which outages should be considered in the benchmark planning case; and 4. Model demand load response in their extreme weather event planning area.[32] **2. Sensitivity Analysis** Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change. For example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation.[33] In developing sensitivities the drafting must: 1. Require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case; and 2. Establish a baseline set of sensitivities for the new or modified Standard. FERC stated that while it would not require the inclusion of any specific sensitivity in Order No. 896, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers.[34] **3. Modifications to the Traditional Planning Approach** The drafting team must require the use of planning methods that ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions that also address: 1. Whether probabilistic elements can be incorporated into the new or modified Standard and implemented presently by responsible entities, and 2. Identify any probabilistic planning methods that would improve upon existing planning practices, but are infeasible to include in a new or modified Standard at this time.[35] **H. Implement a Corrective Action Plan if Performance Standards Are Not Met** The Order specifies that NERC must develop standards that require Corrective Action Plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not

[32] Order at P111 through P116.
[33] Order at P124 and also at P126.
[34] Order at P124.
[35] Order at P134, P138, and P158.

met; therefore, the drafting must require the development of extreme weather corrective action plans that:

1. Identify specified instances when performance standards are not met;
2. Require certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan;
3. Require mitigation for specified instances where performance requirements for extreme heat and cold events are not met (*i.e.,* when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability);
4. Determine whether corrective action plans should be required for single or multiple sensitivity cases;
5. Determine whether corrective action plans should be developed if a contingency event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability;
6. Establish required study contingencies and baseline sensitivities for which a corrective action plan is required; and
7. Require that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.[36]

I. Other Extreme Weather-Related Events and Issues

Reliability Standard Implementation Timeline

NERC must submit a responsive Reliability Standard to FERC by December 23, 2024.

The proposed implementation timeline for a new or modified Reliability Standard must have an implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed new or modified Reliability Standard.[37]

The drafting team in developing the standard has the discretion to develop a phased-in implementation timeline for the different requirements of the proposed Reliability Standard (*i.e.,* developing benchmark cases, conducting studies, developing corrective action plans, etc.). However, this phased-in implementation must begin within 12 months of the effective date of a Commission order approving the proposed Reliability Standard and must include a clear deadline for implementation of all requirements.[38]

Other

There is a concern that there is limited modeling of protection systems in dynamic assessments currently, and any dynamic simulation of extreme events would require significant modeling of protection systems to provide for convergence of the numerical simulation. The drafting team in developing the planning requirements for extreme heat and cold weather must take into account any

Requested information
deficiencies in dynamic modeling of protection systems. The dynamics databases used for transient stability simulations by various interconnections typically do not include comprehensive dynamic models of relays installed in the interconnection. The drafting team should consider wide-area applications by various interconnections that may not typically include comprehensive dynamic models of relays installed in the interconnection.[39] The drafting team should consider the cost impacts to responsible entities.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impact is unknown and will be considered during drafting team meetings. However, The SAR proposes to either create a new Standard or modify an existing Standard(s) that would require responsible entities to create Corrective Action Plans to address risks related to transmission system planning performance for extreme weather directed in the Order. The costs associated are anticipated to be comparable to those associated with a responsible entity's performance of TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
BES facilities may be uniquely impacted by the results of improved studies that incorporate enhanced extreme heat and cold weather scenarios and sensitivity analyses performed by the transmission planners. Mitigating and corrective actions may require transmission system topology changes, including but not limited to re-evaluating load shedding plans as a safety net in response to high demand in extreme heat and cold weather over a wide-area. For example, if studies reveal thermal violations that could be anticipated during extreme weather, transmission facilities may need to be upgraded. Generation facilities may be impacted by having to change the way concurrent or coincident generator outages are managed and planned to reduce the likelihood of not meeting high demands over a wide-area. For example, if multiple generators are disrupted due to pipeline issues and don't have dual fuel capability.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
The development of a new or modified Standard should consider drafting team individuals from the following functional entities: Balancing Authority, Generator Owner, Planning Coordinator, Reliability Coordinator, Transmission Owner, and Transmission Planner.

[36] Order at P152 through P158, and P165.
[37] Order at P188.
[38] Order at P193.
[39] Order at P68 and P74.

Requested information
Do you know of any consensus building activities[40] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
In Order No. 896, FERC highlighted that industry experts agreed that extreme weather events are likely to become more severe and frequent in the future and there is a need to address them in the long-term planning horizon.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
TPL-001-5.1a and MOD-032-1.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

[40] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	No needed Regional or Interconnection variances were identified. The Order did acknowledge that the drafting team consider approaches that would provide a uniform framework for developing benchmark events while still recognizing regional differences in climate and weather patterns, among other considerations; therefore, the use of region is considered to be the common geographical understanding and not NERC Regional Entity footprints. The Commission disagreed that Regional Entities and reliability coordinators should not lead the development of benchmark events and that the drafting team should.[41]

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised

[41] Order at P58.

2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Appendix A

Excerpts from NOPR, 179 FERC ¶ 61,195

P51. February 2011 Southwest Cold Weather Event and January 2014 Polar Vortex Cold Weather Event

81. While balancing authorities and other entities must share system information and study results with their transmission and planning coordinator pursuant to Reliability Standards MOD-032-1 and TPL-001-5.1 as described above, there is no required sharing of such information—**or required coordination**—among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners, thus limiting the benefits of additional modeling. Sharing system information and study results and **enhancing coordination** among these entities for extreme heat and cold weather events could result in more representative planning models by better:

> (1) integrating and including operations concerns (e.g., lessons learned from past issues including corrective actions and projected outcomes from these actions, evolving issues concerning extreme heat/cold) in planning models; and
>
> (2) conveying reliability concerns from planning studies (e.g., potential widespread cascading, islanding, significant loss of load, blackout, etc.) as they pertain to extreme heat or cold.

82. Therefore, as part of its revisions, NERC should require system information and study results sharing, and **coordination** among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners for extreme heat and cold weather events. To better understand the benefits of the suggested actions, we are inviting comments on:

> (1) the parameters and timing of coordination and sharing;
>
> (2) specific protocols that may need to be established for efficient coordination practices; and
>
> (3) potential impediments to the proposed coordination efforts.

Appendix B

Excerpts from Order No. 896
57. Environmental Defense Fund (EDF), Tri-State, and Eversource Energy Service Company (Eversource) propose that reliability coordinators should have the responsibility to perform wide-area planning and coordination in collaboration with other impacted reliability coordinators

64. there is no required sharing of such information related to extreme heat or cold weather events—or required coordination—among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners. Sharing system information and study results and enhancing coordination among these entities for extreme heat and cold weather events could result in more representative planning models by better integrating and including operations concerns (*e.g.,* lessons learned from past issues including corrective actions and projected outcomes from these actions, evolving issues concerning extreme heat/cold) in planning models; and conveying reliability concerns from planning studies (*e.g.,* potential widespread cascading, islanding, significant loss of load, blackout, etc.) as they pertain to extreme heat or cold.[42]

70. Tri-State suggests that the balancing authority should address the results of the studies and how they should communicate those results among the transmission planners. Tri-State also asserts that the balancing authority is responsible for resource adequacy and should communicate resource needs for the area with the responsible transmission planners who can evaluate system needs and "provide access to remove" resource needs.

[42] NOPR at P81.

Project 2021-03 CIP-002

Action

Authorize the solicitation of supplemental standards drafting team (SDT) members.

Background

On January 19, 2022, the Standards Committee (SC) accepted a Request for Interpretation (RFI) submitted by Burns & McDonnell. The SC assigned the RFI to NERC Project 2021-03 – CIP-002 Transmission Owner Control Center (TOCC) and authorized solicitation for supplemental standard drafting team (SDT) members at its February 16, 2022 meeting. From May 23 through June 22, 2022, NERC solicited supplemental nominations for the SDT. The supplemental SDT members were appointed at the September 21, 2022 SC meeting.

After a review of the RFI, the SDT determined that the RFI could be addressed through standards revisions within Project 2021-03. NERC staff worked with the RFI submitters, to draft the CIP-002 Communication Protocol Converters SAR. At its February 22, 2023 meeting, the SC rejected the RFI, accepted the SAR, and assigned the SAR to Project 2021-03 – CIP-002 SDT. The SAR was posted for a 30-day formal comment period from March 2 – March 31, 2023. After reviewing the comments received in response to the SAR posting, the SDT raised concerns that it may lack sufficient subject matter expertise.

Summary

To ensure that the SDT includes sufficient subject matter expertise, NERC staff recommends that the SC authorize the solicitation of supplemental SDT members.

Project 2022-05 Modifications to CIP-008 Reporting Threshold

Action

- Accept the revised Project 2022-05 Modifications to CIP-008 Reporting Threshold Standard Authorization Request (SAR);
- Appoint the Project 2022-05 SAR drafting team (DT) as the Project 2022-05 Standard Drafting Team (SDT); and
- Authorize drafting revisions to the standards identified in the SAR.

Background

In Q3 2021, the ERO Enterprise initiated a study to better understand how registered entities have implemented Reliability Standard CIP-008-6; specifically, how the registered entities have interpreted Reportable Cyber Security Incidents and defined attempt(s) to compromise. The study concluded that the current language of the Reliability Standard permits the use of subjective criteria to define attempt(s) to compromise, and most programs include a provision allowing a level of staff discretion. The resulting white paper concluded that Reliability Standard CIP-008-6, or definitions, should be modified to provide a minimum expectation for thresholds defining attempts to compromise.

The Standards Committee (SC) accepted the SAR at its September 21, 2022 meeting. At the same meeting, the SC authorized soliciting members for the SAR DT. The informal comment period and the solicitation of SAR DT members ran from November 2 – December 5, 2022. The SC appointed 10 members to the SAR DT at its January 25, 2023 meeting. The SAR DT held meetings from February through March to revise the SAR.

At the May 17, 2023 SC meeting, the Committee made a motion to postpone action on the SAR indefinitely, with guidance to the SDT to provide a summary response to the comments submitted. The SAR DT held meetings in May and June to fulfill this request and has posted a summary response to SAR comments on the Project 2022-05 page, as well as an attachment including examples of entity actions provided to the drafting team from NERC and FERC staff during team discussions.

Summary

NERC staff recommends accepting the revised SAR, appointing the SAR DT as the project SDT, and authorizing drafting revisions to the standards listed in the SAR.

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	CIP-008 Reporting Threshold		
Date Submitted:	18 July, 2022 (April 12, 2023)		
SAR Requester			
Name:	Michaelson Buchanan (Revised by the Project 2022-05 SAR DT)		
Organization:	NERC		
Telephone:	470.725.5268	Email:	Michaelson.buchanan@nerc.net

SAR Type (Check as many as apply)	
☐ New Standard	☐ Imminent Action/ Confidential Issue (SPM Section 10)
☒ Revision to Existing Standard	
☒ Add, Modify or Retire a Glossary Term	☐ Variance development or revision
☐ Withdraw/retire an Existing Standard	☐ Other (Please specify)

Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)	
☐ Regulatory Initiation	☒ NERC Standing Committee Identified
☐ Emerging Risk (Reliability Issues Steering Committee) Identified	☐ Enhanced Periodic Review Initiated
☐ Reliability Standard Development Plan	☐ Industry Stakeholder Identified

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):
Improve awareness of existing and future cyber security risks to the BES.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Since the effective date of CIP-008-6, there has not been a perceived change in the number of Reportable Cyber Security Incidents or Cyber Security Incidents that were determined to be an attempt to compromise an applicable system. This project will identify and address potential gaps in CIP-008-6 permitting a subjective determination of attempt(s) to compromise.
Project Scope (Define the parameters of the proposed project):
The Standards Drafting Team (SDT) will modify the Reliability Standards and/or associated definitions as necessary to provide clarity on what constitutes an attempt to compromise. Modifications should be focused on CIP-008-6. The SDT will consider and modify if necessary other related standards.

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide (1) a technical justification[1] that includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide the development of the Standard or definition):
Reliability Standard CIP-008-6 became effective on January 1, 2021, in response to FERC Order No. 848[3] directing NERC to develop modifications to the Reliability Standards to require reporting of Cyber Security Incidents and attempt(s) to compromise a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS). In Q3 2021, the ERO Enterprise initiated a study to better understand how registered entities have implemented Reliability Standard CIP-008-6; specifically, how the registered entities have interpreted Reportable Cyber Security Incidents and defined attempt(s) to compromise. The study concluded the current language of the Reliability Standard permits the use of subjective criteria to define attempt(s) to compromise, and most programs include a provision allowing a level of staff discretion. Reliability Standard CIP-008-6 or definitions should be modified to provide a minimum expectation for thresholds defining an attempt to compromise.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impact to entities is unknown at this time, however, a question will be asked during all comment periods to receive entity input and ensure all aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*., Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Reliability Coordinator, Transmission Operator, Transmission Owner
Do you know of any consensus-building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus-building activity.
In Q3-2021, the NERC Compliance Assurance and ERO Enterprise initiated a study to better understand how registered entities have implemented Reliability Standard CIP-008-6 in response to modifications; specifically, how the registered entities are interpreting Reportable Cyber Security Incidents and defining attempt(s) to compromise. The study team reviewed previous compliance monitoring engagements to analyze ERO Enterprise CMEP data and conducted a questionnaire engagement with

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

[3] Cyber Security Incident Reporting Reliability Standards, Order No. 848, 164 FERC ¶ 61,033 (2018).

Requested information
approximately 30 registered entities through voluntary mechanisms (e.g., entity engagements, webinars, onsite visits, etc.). The questionnaires focused on four key areas: 1) criteria for reporting and key definitions, 2) organizational internal controls, 3) training and tools, and 4) reporting. The study concluded that the current language of the Reliability Standard permits the use of subjective criteria to define an attempt to compromise, and most programs included a provision that allows a level of discretion by staff. Other aspects of the CIP-008 Reliability Standard were found to be sufficient.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
Project 2016-02 includes modifications to the applicable systems listed in CIP-008-6.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for an emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☐	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, and qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
☒	8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes

Market Interface Principles	
3. A reliability standard shall not preclude market solutions from achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
N/A	

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SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as a Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	CIP-008 Reporting Threshold		
Date Submitted:	18 July, 2022 (April 12, 2023)		
SAR Requester			
Name:	Michaelson Buchanan (Revised by the Project 2022-05 SAR DT)		
Organization:	NERC		
Telephone:	470.725.5268	Email:	Michaelson.buchanan@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Improve awareness of existing and future cyber security risk to the BES.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Since the effective date of CIP-008-6 there has not been a perceived ~~material~~ change in the number of Reportable Cyber Security Incidents or Cyber Security Incidents that were determined to be an attempt to compromise an applicable system. This project will identify and address potential gaps in CIP-008-6 permitting a subjective determination of attempt(s) to compromise.			
Project Scope (Define the parameters of the proposed project):			
The Standards Drafting Team (SDT) will modify the Reliability Standards and/or associated definitions as necessary to provides clarity on what constitutes an ~~a minimum expectation for thresholds to support the definition of~~ attempt to compromise. Modifications should be focused on CIP-008-6. The SDT will consider and modify if~~, however, it may be~~ necessary ~~to modify~~ other related standards ~~for consistency~~.			

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Reliability Standard CIP-008-6 became effective on January 1, 2021, in response to FERC Order No. 848[3] directing NERC to develop modifications to the Reliability Standards to require reporting of Cyber Security Incidents and attempt(s) to compromise a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS). In Q3 2021, the ERO Enterprise initiated a study to better understand how registered entities have implemented Reliability Standard CIP-008-6; specifically, how the registered entities have interpreted Reportable Cyber Security Incidents and defined attempt(s) to compromise. The study concluded the current language of the Reliability Standard permits the use of subjective criteria to define attempt(s) to compromise, and most programs include a provision allowing a level of staff discretion. Reliability Standard CIP-008-6 or definitions should be modified to provide a minimum expectation for thresholds defining attempt to compromise. ~~To accomplish this, CIP-008-6 R1 Part 1.2.1 could be modified to read, "…That include criteria to evaluate and define attempts to compromise which include, at a minimum, each of the following types of cyber security incidents:…". Conversely, it may be possible to modify the NERC Glossary definition of Reportable Cyber Security Incident to include attempt to compromise along with threshold criteria. There are other examples in the NERC Glossary of Terms, such as Removable Media which include minimum expectation examples. These are examples and not the only possible solutions. Regardless of the approach, thresholds should not be so prescriptive as to require the reporting of every internet facing firewall port scan, phishing email identified, or file alerted by endpoint anti-virus scans. Rather, the intent would be to right size the reporting threshold to improve awareness of existing and future cyber security risks to the BES.~~
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
~~No additional~~The cost impact to entities is unknown at this ~~outside of the~~ time, ~~and resources needed to serve on the Standard Drafting Team are expected. H~~however~~,~~ a question will be asked during all ~~the SAR~~ comment periods to receive entity input and ensure all aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Reliability Coordinator, Transmission Operator, Transmission Owner

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
In Q3-2021, the NERC Compliance Assurance and ERO Enterprise initiated a study to better understand how registered entities have implemented Reliability Standard CIP-008-6 in response to modifications; specifically, how the registered entities are interpreting Reportable Cyber Security Incidents and defining attempt(s) to compromise. The study team reviewed previous compliance monitoring engagements to analyze ERO Enterprise CMEP data and conducted a questionnaire engagement with approximately 30 registered entities through voluntary mechanisms (e.g., entity engagements, webinars, onsite visits, etc.). The questionnaires focused on four key areas: 1) criteria for reporting and key definitions, 2) organizational internal controls, 3) training and tools, and 4) reporting. The study concluded that the current language of the Reliability Standard permits the use of subjective criteria to define attempt to compromise, and most programs included a provision which allows a level of discretion by staff. Other aspects of the CIP-008 Reliability Standard were found to be sufficient.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
Project 2016-02 includes modifications to the applicable systems listed in CIP-008-6. ~~Once approved, CIP-008-6 will increment to CIP-008-7.~~
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.
[3] Cyber Security Incident Reporting Reliability Standards, Order No. 848, 164 FERC ¶ 61,033 (2018).

Reliability Principles	
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☒	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
N/A	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised

2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Project 2022-04 EMT Modeling

Action

- Accept the revised Project 2022-04 EMT Modeling Standard Authorization Request (SAR);
- Appoint the Project 2022-04 EMT Modeling SAR Drafting Team (DT) as the Project 2022-04 EMT Modeling Standard Drafting Team (SDT); and
- Authorize drafting revisions to the Reliability Standards identified in the SAR.

Background

The primary objective of the SAR is to enhance reliability by ensuring Transmission Planners (TPs) and Planning Coordinators (PCs) have the models and tools necessary to adequately conduct reliability assessments under increasing levels of inverter-based resources. This requires the collection of electromagnetic transient (EMT) models by applicable entities and TPs and PCs to conduct EMT studies where needed.

The Standards Committee (SC) accepted the SAR that was submitted by the Inverter-Based Resources Performance Subcommittee (IRPS) at its July 20, 2022 meeting. At the same meeting, the SC authorized soliciting members for the SAR DT. The informal comment period and the solicitation for the SAR Drafting Team member period ran from August 11, 2022 – September 13, 2022. The SC appointed 13 members to the SAR DT at its December 13, 2022 meeting. The SAR DT conducted several meetings reviewing and addressing the comments received and making revisions to the SAR.

Summary

NERC staff recommends accepting the revised SAR, authorizing drafting revisions identified in the SAR, and appointing all 13 members from the SAR DT as the project SDT.

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	EMT Modeling		
Date Submitted:	June 8, 2022 (Revised on May 15, 2023)		
SAR Requester			
Name:	Allen Schriver, NextEra Energy (NERC IRPS Chair) Julia Matevosyan, ESIG (NERC IRPS Vice Chair)		
Organization:	NERC Inverter-Based Resource Performance Subcommittee (IRPS) (Revised by Project 2022-04 SAR DT)		
Telephone:	Allen – 561-904-3234 Julia – 512-994-7914	Email:	allen.schriver@fpl.com julia@esig.energy
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The bulk power system (BPS) in North America is undergoing a rapid transformation towards high penetrations of inverter-based resources (IBR). Transmission Planners (TP) and Planning Coordinators (PC) are concerned about the lack of accurate modeling data and the need to perform electromagnetic transient (EMT) studies during the interconnection and planning processes. The growth of inverter technology has pushed conventional planning tools to their limits in many ways. TPs and PCs are now faced with the need to conduct more detailed studies using EMT models for issues related to inverter-based resource integration. This SAR proposes including EMT models and studies in planning-related NERC Standards to ensure reliable operation of the BPS moving forward. See supporting paper[1] for more details.			

[1] IRPS Supporting Paper

Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This project addresses the reliability-related need and benefit by ensuring TPs and PCs have accurate models necessary to adequately conduct reliability studies under increasing levels of inverter-based resources. This requires the collection of EMT models by applicable entities in order to conduct EMT studies. Furthermore, this proposed project addresses reliability issues identified in the NERC disturbance reports by accomplishing the following: • Ensuring that the TP and PC defined interconnection study process is clear on the modeling and study requirements needed to ensure reliable operation of the BPS, inclusive of EMT modeling and studies. • Ensuring that EMT models are available to TPs and PCs for the purposes of reliability studies. • Ensuring that model quality issues are addressed both during interconnection study process and post facility commissioning. • Ensuring that EMT studies are conducted per TPs and PCs defined processes during the interconnection study process and after commercial operation. • Ensuring that relevant modeling data is collected and verified.
Project Scope (Define the parameters of the proposed project):
This scope of the project is to modify applicable NERC standards and/or develop new NERC standards in order to: i. Create and incorporate EMT model and study requirements, and ii. Include EMT model quality verification[2] processes and functional tests[3] to ensure models meet the requirements defined in item i.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Defined terms will be created as needed. It is anticipated that the following standards may be impacted: FAC-002, MOD-032, and TPL-001. The proposed modifications would address the following identified gaps:

[2] For the purposes of this SAR, the term "verification" refers to the static process of checking documents and files, and comparing them to model parameters, model structure, or equipment settings.
[3] For the purposes of this SAR, the term "functional tests" refers to tests that confirm model usability, initialization, and interoperability.
[4] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
• NERC FAC-002 Enhancements or New Standard: o **TP and PC Create and Incorporate EMT Model and Study Requirements:** Consider requirements for TP and PC to establish EMT model and study requirements as part of the interconnection process. o **Ensure Accurate Models are Provided, Verified, and Validated Prior to Commercial Operation:** Consider a requirement that TP and PC shall follow a defined process to verify that the model and study requirements used in FAC-002 interconnection studies meet the TP and PC defined model requirements. Consider a requirement that Generator Owner (GO) shall provide accurate models along with sufficient evidence to support verification of requirements by the TP and PC. The benchmarking between the positive sequence and EMT models should be conducted by the GO. The final verification of the models should be conducted at the time of plant commissioning or during trial operations. The requirement should state that an updated model (if required) be provided to ensure the models used in studies match the actual plant configuration, equipment, and settings. Proof of accuracy for EMT models should be provided for the type of phenomena these models will be used to assess. The GO shall provide sufficient documentation to ensure control modes, settings, protections, and performance match between the models and the installed equipment. Discrepancies between models or validation[5] results throughout the interconnection process may require re-studies by the TP to ensure reliable operation prior to commercial operation. The GO may be subject to any operational constraints by the Transmission Operator (TO) and Reliability Coordinator (RC) until the facility can be operated in a planned and studied operating state. o **Clarify Requirements on Applicable Entities Providing Accurate Models:** Clarify existing requirements that use vague terms like “coordinate and cooperate” to more explicitly state that the applicable entities will provide accurate models meeting the TP and PC modeling requirements (including model quality specifications), and that any modifications to equipment or settings shall be communicated to the TP and PC for determination if any additional reliability studies are necessary. • NERC MOD-032 Enhancements or New Standard: ***NOTE*:** The IRPS believes that these enhancements could be made by either modifying MOD-032 or introducing a new NERC Standard specifically focused on gathering EMT models and modeling data for the purposes of reliability studies. The IRPS generally believes that concepts of Requirement R1 and Attachment 1 are applicable for EMT modeling/studies; however, the development of interconnection-wide cases to the MOD-032 designee and annual case creation process may not be applicable for EMT studies.

[5] For the purposes of this SAR, the term “validation” refers to the dynamic process of testing or monitoring the equipment behavior, and then using the testing or monitoring results and comparing them to the model simulated response

Requested information
◦ **Explicit Inclusion of EMT Models:** Consider a requirement that explicitly states the TP and PC should define EMT modeling requirements. The TP and PC defined EMT modeling requirements should at minimum include a clearly documented process for determining when EMT models shall be required from applicable entities. The process should directly specify that all models, including EMT, represent the equipment installed in the field. Any modeling deficiencies identified by the TP and PC should be addressed by the applicable entity in a timely manner. The standard should ensure that any TP or PC conducting EMT studies are able to obtain sufficient modeling information. Any TP and PC should have the authority to secure EMT models and/or modeling data from any applicable entity within a time limit defined in the standard. • NERC TPL-001 Enhancements or New Standard: ◦ **Process for Conducting EMT Studies:** Consider a requirement that the TP and PC shall develop a process/rationale for determining when detailed studies using EMT models are required as per TP and PC requirements. TPs and PCs shall then perform EMT studies for situations that meet the rationale. ◦ **Stability Criteria:** The drafting team should ensure that the criteria is appropriate and applicable for the EMT studies. The standards revisions will apply to TPs and PCs as they conduct interconnection and planning studies. TOs need to supply EMT modeling data for the transmission network, and GOs need to provide accurate EMT models to the TP/PC for studies. FAC-002 presently applies implicitly to the developers of new facilities since the TP/PC have a study process for studying new resources prior to interconnection. The inclusion of EMT modeling requirements apply to, but not limited to; generating resources (inverter-based and synchronous), synchronous condensers, transmission-connected dynamic reactive devices (e.g., FACTs controllers), transmission elements, remedial action schemes (RAS), and any other elements necessary for reliability study purposes. Models of all elements in the areas for which an EMT study is required are needed to create an accurate network model to study possible reliability risks. The supporting paper[6] provides a list of reference materials and documentation that serve as a strong technical basis for these changes to the NERC Standards. Most notably, the Odessa disturbance report (2021) and CA disturbance report (2022) strongly emphasize enhancements to the NERC Standards. These specifically focus on inclusion of accurate and reliable EMT models (in addition to accurate and reliable positive sequence models) along with updates to address model quality for reliability studies.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Exact costs for this project are unknown. Near-term costs are likely to increase as industry develops

[6] IRPS Supporting Paper

Requested information
practices around development, collection, and use of EMT models for reliability studies; however, the team believes that long-term costs will likely be minor as industry is already expanding necessary skills and expertise in this area across many areas of the world. OEMs are developing real-code models, generator owners are gaining familiarity with existing EMT modeling requirements, and transmission planners are gaining experience conducting or managing EMT studies. Generation and transmission entities will likely experience up-front and ongoing costs in areas where EMT studies are becoming increasingly necessary from a grid reliability standpoint. These costs are recognized; however, the team has made a focused and concerted effort to minimize costs while achieving necessary reliability outcomes for this project. Outcomes from this project, ensuring an adequate level of reliability for the BES, significantly outweigh the incremental costs of implementation from this proposed project.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*., Dispersed Generation Resources):
No BES facilities will be directly impacted by the proposed standard modifications. Asset owners of BES facilities (GOs, TOs) will be required to provide EMT models and/or modeling data, where applicable, and ensure quality of the models submitted to the TP and PC.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*., Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owners, Transmission Planners, Planning Coordinators, Generator Owners, Distribution Provider, Resource Planner, Transmission Service Provider, equipment manufacturers, consultants conducting EMT studies, and any other EMT modeling and studies experts.
Do you know of any consensus building activities[7] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR was developed by the NERC IRPS, a large group of industry experts focused specifically on ensuring reliable operation of the BPS under increasing penetrations of BPS-connected inverter-based resources. This SAR was also endorsed by the NERC RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
Project 2020-06, Project 2022-02, Project 2023-02, Project 2021-01, EMT Task Force, IRPS, and other projects that might impact this effort.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

[7] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information
NERC has published a number of disturbance reports and guidelines highlighting the need for these changes to be made to NERC Standards. NERC has also published modeling-related Alerts for inverter-based resources to raise industry awareness of ongoing modeling challenges. NERC IRPS has also published numerous guidelines, technical reports, white papers, etc. to help educate industry and recommend best practices. However, the recommendations are not sufficient to ensure accurate EMT studies are conducted for ensuring BES reliability with increasing levels of inverter-based resources.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	EMT Modeling~~EMT Models in NERC MOD, TPL, and FAC Standards~~		
Date Submitted:	June 8, 2022 (Revised on May 15, 2023)		
SAR Requester			
Name:	Allen Schriver, NextEra Energy (NERC IRPS Chair) Julia Matevosyan, ESIG (NERC IRPS Vice Chair)		
Organization:	NERC Inverter-Based Resource Performance Subcommittee (IRPS) (Revised by Project 2022-04 SAR DT)		
Telephone:	Allen – 561-904-3234 Julia – 512-994-7914	Email:	allen.schriver@fpl.com julia@esig.energy
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The bulk power system (BPS) in North America is undergoing a rapid transformation towards high penetrations of inverter-based resources (IBR). Transmission Planners (TP) and Planning Coordinators (PC) are concerned about the lack of accurate modeling data and the need to perform electromagnetic transient (EMT) studies during the interconnection and planning processes~~ and long-term planning horizon~~. The growth of inverter technology has pushed conventional planning tools to their limits in many ways.~~, and~~ TPs and PCs are now faced with the need to conduct more detailed studies using EMT models for issues related to inverter-based resource integration~~ issues~~. This SAR proposes including EMT models and studies in planning-related NERC Standards to ensure reliable operation of the BPS moving forward. See~~ attached~~ supporting paper[1] for more details.			

[1] IRPS Supporting Paper

Requested information

Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):

This project addresses the reliability-related need and benefit by ensuring TPs and PCs have accurate models necessary to adequately conduct reliability studies~~assessments~~ under increasing levels of inverter-based resources. This requires the collection of EMT models by applicable entities~~ and TPs and PCs~~ in order to conduct EMT studies~~ where needed~~. Furthermore, this proposed project addresses reliability issues identified in the NERC disturbance reports by accomplishing the following:

- Ensuring that the TP and PC defined interconnection study process is clear on the modeling and study requirements needed to ensure reliable operation of the BPS, inclusive of EMT modeling and studies~~ (NERC FAC-002)~~.
- Ensuring that EMT models are available to TPs and PCs for the purposes of reliability studies.~~ – interconnection studies per FAC-002 and planning assessments per TPL-001 (using MOD-032 as the modeling data standard, or a new standard if deemed necessary)~~
- Ensuring that model quality issues are addressed both during interconnection study process and post facility commissioning.~~ies (FAC-002) and during annual case creation and planning assessments (MOD-032/TPL-001)~~
- Ensuring that EMT studies are conducted per~~by~~ TPs and PCs defined processes during the interconnection study process~~ (FAC-002)~~ and after commercial operation.
- Ensuring that relevant modeling data is collected and verified.~~during annual planning assessments (TPL-001) if the TP or PC identifies a reliability need to conduct these studies (i.e., on an as-needed basis with technical justification).~~

Project Scope (Define the parameters of the proposed project):

This scope of the project is to modify applicable NERC standards and/or develop new NERC standards in order to:~~project will modify three existing NERC Standards – FAC-002, MOD-032, and TPL-001. The scope of the project is to modify NERC standards to 1~~

i. Create and incorporate EMT model and study requirements, and~~.~~

~~i.~~ii. Include EMT model quality verification[2] processes and functional tests[3] to ensure models meet the requirements defined in ~~bullet 1~~item i.~~) include specific requirements for EMT modeling and EMT studies, where needed, and 2) ensure accurate models are provided by applicable entities and corrections to modeling errors are addressed in a timely manner.~~

[2] For the purposes of this SAR, the term "verification" refers to the static process of checking documents and files, and comparing them to model parameters, model structure, or equipment settings.

[3] For the purposes of this SAR, the term "functional tests" refers to tests that confirm model usability, initialization, and interoperability.

Requested information

Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):

~~Create d~~Defined terms will be created as needed.

It is anticipated that the following standards may be impacted: FAC-002, MOD-032, and TPL-001.

~~The proposed project will produce three deliverables – modifications to FAC-002, modifications to MOD-032 (or a new standard related to EMT model collection), and modifications to TPL-001. Modifications to each standard seek to (1) incorporate EMT modeling and studies, as applicable, and (2) include model quality checks for all models used in reliability studies.~~ The proposed modifications would address the following identified gaps~~for each standard include the following~~:

- NERC FAC-002 Enhancements or New Standard:
  - **TP and PC Create and ~~i~~Incorporate~~Conduct~~ EMT Model and Study Requirements~~ies Where Necessary~~:** Consider requirements for TP and PC to establish EMT model~~s~~ and study requirements as part of the interconnection process.~~Modify the standard to include studies involving EMT models, where necessary, as part of the interconnection study process. The drafting team may consider adding a statement in Requirement R1.3 to include EMT studies.~~
  - ~~o~~ **Ensure Accurate Models are Provided, ~~and~~ Verified, and Validated Prior to Commercial Operation:** Consider~~Include~~ a requirement that~~the~~ TP and PC shall follow a defined~~have a~~ process to verify~~(i.e., sign off)~~ that the model and study requirements~~s~~ used in FAC-002 interconnection studies meet the TP and PC defined model requirements~~as defined by the TP and PC~~. Consider a requirement that Generator Owner (GO) shall provide accurate models along with sufficient evidence to support verification of requirements by the TP and PC. The benchmarking between the positive sequence and EMT models should be conducted by the GO. ~~are a reasonable representation of the plant being commissioned prior to commercial operation. This verification should focus on, at a minimum, the following:~~
  - ~~o Converter-level[5] control modes, settings, and protections~~

~~Plant-level control modes and settings~~

  - ~~Applicable facility protection systems~~

    The final~~is~~ verification of the models should be conducted at the time of plant commissioning or during trial operations. The requirement should state that an updated model (if required) be provided~~corrective actions be implemented~~ to ensure

[4] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

~~[5] Converter is used here rather than inverter to also include possible controls and protections in hybrid plants that may utilize dc/dc converters~~

Requested information
the models used in studies match the actual plant configuration, equipment, and settings. Proof of accuracy for EMT models~~and positive sequence models~~ should be provided for the type of phenomena these models will be used to assess.~~, including large disturbances (faults), control behavior and interactions, etc.~~ The GO shall provide sufficient documentation to ensure control modes, settings, ~~and~~ protections, and performance match between the models and the installed equipment. Discrepancies between models or validation[6] results throughout the interconnection process may require re-studies by the TP to ensure reliable operation prior to commercial operation. The GO ~~and~~ may be subject to any operational constraints by the Transmission Operator (TO~~P~~) and Reliability Coordinator (RC) until the facility can be operated in a planned and studied operating state. ◦ **Clarify Requirements on Applicable Entities Providing Accurate Models:** Clarify existing requirements that use vague terms like “coordinate and cooperate” to more explicitly state that the applicable entities will provide accurate models meeting the TP and PC modeling requirements (including model quality specifications), and that any modifications to equipment or settings ~~during the interconnection study process~~ shall be communicated to the TP and PC for determination if any additional reliability studies are necessary. • NERC MOD-032 Enhancements or New Standard: ***NOTE*:** The IRPS believes that these enhancements could be made by either ~~from~~ modifying ~~ications to~~ MOD-032 or ~~by~~ introducing a new NERC Standard specifically focused on gathering EMT models and modeling data for the purposes of reliability studies. The IRPS~~team~~ generally believes that concepts of Requirement R1 and Attachment 1 are applicable for EMT modeling/studies; however, the development of interconnection-wide cases to the MOD-032 d~~D~~esignee and annual case creation process may not be applicable for EMT studies. ~~o~~ **Explicit Inclusion of EMT Models**~~: Consider~~**:** Consider a requirement that explicitly states the TP and PC should define ~~Modify standard requirements, where applicable, to replace “dynamics” and differentiate between EMT and RMS fundamental frequency positive sequence models. Modify Attachment 1 of the standard to explicitly include~~ EMT modeling requirements. The TP and PC defined EMT modeling requirements should at minimum include~~, but not limited to,~~ a clearly documented process for determining when EMT models shall be required from applicable entities. The process should directly specify that all models, including EMT, represent the equipment installed in the field. Any modeling deficiencies identified by the TP and PC should be addressed by the applicable entity in a timely manner.~~, where necessary, and include specific details relevant for EMT studies. Include sufficient – in t~~The standard~~, to~~ should ensure~~detail in the table such~~ that any TP~~s and~~ or PC~~s~~ conducting EMT studies ~~can~~

[6] For the purposes of this SAR, the term “validation” refers to the dynamic process of testing or monitoring the ~~in-service~~ equipment behavior, and then using the testing or monitoring results and comparing them to the model simulated response

Requested information
~~ensure they~~ are able to obtain sufficient ~~gather sufficient~~ modeling information ~~from applicable entities~~. ~~BPS elements that the TP and PC need to gather modeling information for may include, at a minimum:~~ Any TP and PC should have the authority to secure EMT models and/or modeling data from any applicable entity within a time limit defined in the standard. ~~o Transmission elements, including transmission-connected reactive devices (SVCs, STATCOMs, etc.)~~ ~~Generating resources, both inverter-based (converter controls, plant-level controller controls, and any other applicable control systems) and synchronous~~ ~~HVDC circuits~~ ~~o Other information requested by the PC or TP necessary for modeling purposes~~ ~~o **Process for Collection of EMT Models and Modeling Data:** Ensure that the standard clearly states that the TP and PC should have a clearly documented process for determining when EMT models and modeling data shall be required from applicable entities. EMT models are not necessarily required in all instances from all entities. However, if and when the TP and PC require EMT models and data to conduct EMT studies, they shall have the authority to gather EMT models from applicable entities for the purposes of performing reliability studies. The TP and PC should use MOD-032 to gather data to create localized or regional models or base cases for reliability studies; the intent is not to create a requirement for interconnection-wide EMT models unless the TP and PC have a reliability need to do so (i.e., can be specified per Requirement R1 as part of the TP and PC modeling requirements and reporting procedures).~~ o ~~**Model Quality Enhancements:** Modify standards requirements to more clearly and explicitly specify that all models, including EMT, are accurate and represent the equipment installed in the field. Any modeling deficiencies should be identified by the TP and PC and addressed by the applicable entity in a timely manner. Model quality should be assessed by the TP and PC during the annual case creation process to ensure models are accurate for use in reliability studies. Presently the standard provides an option for the TP and PC to consider, but does not require entities to ensure model quality as part of the process.~~ ~~•~~ NERC TPL-001 Enhancements or New Standard: • ~~o **Differentiate Stability Portions:** Modify the stability portions of the standard (e.g., Requirements R2 and R4) to more clearly and accurately differentiate between studies using EMT models and studies using RMS fundamental frequency positive sequence models. Ensure that all standard requirements, Table 1, and Attachments are clear in this regard.~~ o **Process for Conducting EMT Studies:** Consider~~Include~~ a requirement that the TP and PC shall develop a process/rationale for determining when detailed studies using EMT models are required as per TP and PC requirements. ~~ments such that those studies are done in specific and limited scenarios where they are necessary.~~ TPs and PCs shall then perform EMT studies for situations that meet the rationale. ~~This will require gathering suitable models, per MOD-032 and determining appropriate study~~

Requested information
~~assumptions, contingency events, etc. Study requirements and assumptions should be specified in TPL-001, to the extent possible.~~ ○ ~~**Appropriate**~~ **Stability Criteria:** T~~Modify Requirements R5 and R6 to ensure that stability criteria for inverter-based resources is clear, consistent, and appropriate for both EMT and RMS fundamental frequency positive sequence simulations. If additional stability criteria should be specified for EMT studies, then t~~he drafting team should ensure that the criteria is appropriate and applicable for the EMT~~different~~ studies. ~~The requirements shall also be enhanced to clearly state that the TP and PC shall develop corrective action plans when the instabilities are identified, applicable and clear for inverter-based resources in addition to synchronous generation (both in EMT and RMS fundamental frequency positive sequence simulations).~~ The standards revisions will apply to TPs and PCs as they conduct interconnection ~~studies~~ and planning studies.~~assessments,~~ TOs ~~that may~~ need to supply EMT ~~models~~ modeling data for the transmission network, and GOs need to~~as they~~ provide accurate ~~generator modeling information~~EMT models to the TP/PC for studies. FAC-002 presently applies implicitly to the developers of new facilities ~~(~~since the TP/PC have a study process for studying new resources prior to interconnection~~);~~ ~~this SAR does not seek to change existing applicability of any standards, only strengthen and improve requirements to address known reliability gap~~.~~s.~~ The inclusion of EMT modeling requirements apply to, but not limited to; ~~-~~generating resources (inverter-based and synchronous), synchronous condensers, transmission-connected dynamic reactive devices (e.g., FACTs controllers~~STATCOMs, SVCs, etc.~~), transmission elements, remedial action schemes (RAS), and any other elements necessary for reliability study purposes. Models of all ~~BPS~~ elements in the areas for which an EMT study is required are needed to create an accurate network model to study possible reliability risks. ~~See supporting paper for more details.~~ The ~~attached supporting paper~~ supporting paper[7] provides a list of reference materials and documentation that serve as a strong technical basis for these changes to the NERC Standards. Most notably, the Odessa disturbance report (2021) and CA disturbance report (2022) strongly emphasize enhancements to the NERC Standards. ~~and~~ These specifically focus on inclusion of accurate and reliable EMT models (in addition to accurate and reliable positive sequence models) ~~and~~ along with updates to address model quality for reliability studies.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Exact costs for this project are unknown. Near-term costs are likely to increase as industry develops practices around development, collection, and use of EMT models for reliability studies; however, the team believes that long-term costs will likely be minor as industry is already expanding necessary skills and expertise in this area across many areas of the world. OEMs are developing real-code models, generator owners are gaining familiarity with existing EMT modeling requirements,

[7] IRPS Supporting Paper

Requested information
and transmission planners are gaining experience conducting or managing EMT studies. Generation and transmission entities will likely experience up-front and ongoing costs in areas where EMT studies are becoming increasingly necessary from a grid reliability standpoint. These costs are recognized; however, the team has made a focused and concerted effort to minimize costs while achieving necessary reliability outcomes for this project. Outcomes from this project, ~~to ensure~~ensuring an adequate level of reliability for the BES, significantly outweigh the incremental costs of implementation from this proposed project.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
No BES facilities will be directly impacted by the proposed standard modifications. Asset owners of BES facilities (GOs, TOs) will be required to provide EMT models and/or modeling data, where applicable, and ensure ~~model~~ quality of the models submitted to the TP and PC. ~~The TP and PC will be required to verify model quality and perform EMT studies using these models, as needed for reliability purposes.~~
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owners, Transmission Planners, Planning Coordinators, Generator Owners, Distribution Provider, Resource Planner, Transmission Service Provider, equipment manufacturers, consultants conducting EMT studies, and any other EMT modeling and studies experts.
Do you know of any consensus building activities[8] in connection with this SAR? ~~–~~ If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR was developed by the NERC IRPS, a large group of industry experts focused specifically on ensuring reliable operation of the BPS under increasing penetrations of BPS-connected inverter-based resources. This SAR was also endorsed by the NERC RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? ~~–~~ If so, which standard(s) or project number(s)?
Project 2020-06, Project 2022-02, Project 2023-02, Project 2021-01, EMT Task Force, IRPS, and other projects that might impact this effort. ~~*Verification of Models and Data for Generators* is focused on validation of models, inclusive of positive sequence dynamic models and EMT models. This SAR is recommending that model verification and submittal by the GO (and model quality checks by the TP) occurs prior to commercial operation; whereas the existing MOD-026 and MOD-027 standards allow for a time period (e.g., 1 year) after commercial operation to correct model errors. However, this can lead to reliability issues not being identified during interconnection studies. Therefore, Project 2020-06 should consider the recommendations in this SAR and these efforts can be aligned for both projects. If that project is completed by the time a new SAR Drafting Team is stood up for this~~

[8] Consensus building activities are occasionally conducted by NERC and/or project review teams. ~~–~~ They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information
~~proposed project, then the new Standard Drafting Team could help ensure alignment. These efforts are in alignment and complement each other. This SAR is not seeking to change any NERC Glossary Terms and therefore will not affect any other standards in this manner.~~
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
NERC has published a number of disturbance reports and ~~reports~~guidelines highlighting the need for these changes to be made to NERC Standards. NERC has also published modeling-related Alerts for inverter-based resources to raise industry awareness of ongoing modeling challenges. NERC IRPS has also published numerous guidelines, technical reports, white papers, etc. to help educate industry and recommend best practices. However, the recommendations are not sufficient to ensure accurate EMT studies are conducted for ensuring BES reliability with increasing levels of inverter-based resources.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes

Market Interface Principles	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
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4	February 25, 2020	Standards Information Staff	Updated template footer

Project 2023-01 EOP-004 IBR Event Reporting

Action
Authorize initial posting of proposed Reliability Standard EOP-004-5 and the associated Implementation Plan for a 45-day formal comment period, with ballot pools formed in the first 30 days, and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

Background
Project 2023-01 will modify the existing generation loss criteria under EOP-004, to make it more suitable and appropriate for reporting inverter-based resource (IBR) events. The current EOP-004 provisions addressing reporting of generation loss events use relatively large size thresholds more suitable for synchronous generation. NERC and the Regional Entities analyzed multiple widespread solar PV loss events (some also involving other generation losses) across many resources that did not meet the EOP-004 criteria for reporting. NERC and the Regional Entities concluded that many of these resources have systemic reliability risks posed by IBRs that should be reported by applicable entities, but are not captured under EOP-004. This project will modify the existing generation loss criteria so that it aligns with past large-scale disturbances analyzed by the ERO.

The Reliability and Security Technical Committee (RSTC) endorsed the Standard Authorization Request (SAR) on December 6, 2022. The Standards Committee (SC) accepted the SAR and authorized soliciting for members for the SAR drafting team (SAR DT) at its January 25, 2023 meeting. The SC appointed the SAR DT at its April 19, 2023 meeting. At its May 17, 2023 meeting, the SC accepted the revised SAR, appointed the SAR DT as the standards drafting team (SDT), and authorized revisions to EOP-004-4. The SDT has since met multiple times to discuss revisions and draft an associated Implementation Plan.

The Quality Review (QR) for this posting was performed from June 7 – 22, 2023. The QR team members from ERO Enterprise included Alain Riguad, Nina Johnston, Rachel Coyne, and Steve Rueckert. Industry partners included N. Shannon Brown (TVA), Christopher Moran (PJM), and Daniel Koppes (PacifiCorp).

Summary
NERC staff recommends that the SC authorize the initial posting of the proposed Reliability Standard EOP-004-5 and the Implementation Plan for a 45-day formal comment period, with ballot pools formed in the first 30 days, and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 7 – March 8, 2023

Anticipated Actions	Date
45-day formal or informal comment period with ballot	July to September 2023
45-day formal or informal comment period with additional ballot	December 2023 to January 2024
45-day final ballot	February 2024
Board adoption	May 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-004-5

3. **Purpose:** To improve the reliability of the Bulk Electric System (BES) by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following Functional Entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-5.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-5 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-5 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-004-5 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-5 Attachment 2 form or a DOE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

C. Compliance

1. Compliance Monitoring Process

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

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 48 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the end of the next business day, as applicable.	the end of the next business day, as applicable.	end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-5 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written event report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-417 form) pursuant to Requirements R1 and R2.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction resulting from a BES Emergency	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction resulting from a BES Emergency	TOP	System-wide voltage reduction of 3% or more.
Firm load shedding resulting from a BES Emergency	Initiating RC, BA, or TOP	Firm load shedding ≥ 100 MW (manual or automatic).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of =/> 10% of nominal voltage sustained for ≥ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for ≥ 15 minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities.
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW.
Generation loss	BA	Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
IBR generation loss	BA	Total aggregated generation loss of ≥ 500 MW from inverter-based resource(s) (IBR)[1] occurring within a 30 second period. IBR generation loss shall be calculated using Telemetering data[2] by subtracting the lowest aggregated IBR generation output observed during a 30 second period from the pre-disturbance aggregated IBR generation output.
Loss of DC Tie Line	BA	Loss of a DC Tie Line, between two separate asynchronous systems, loaded at ≥ 500 MW.

[1] For the purposes of EOP-004-5, an IBR is a generation resource consisting of one or more IBR unit(s) that connect to the transmission or subtransmission system via a single point of connection. An IBR unit is a primary energy source containing an individual inverter device, individual converter device, or a grouping of multiple inverters/converters. IBR units include solar photovoltaic, Type 3 and Type 4 wind, battery energy storage, high voltage direct current (HVDC) transmission, and dynamic reactive devices such as static synchronous compensators (STATCOMs) and static VAR compensators (SVCs).

[2] Indicated IBR generation loss due to a failure of SCADA or Telemetering data is not reportable under this requirement.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements.
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE-417 form in lieu of this form, if the entity is required to submit a DOE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
	Task	**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No ☐ Unknown ☐
4.	**Event Identification and Description:**	
	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical threat to its Facility ☐ Physical threat to its BES control center ☐ BES Emergency: ☐ firm load shedding ☐ public appeal for load reduction ☐ System-wide voltage reduction ☐ voltage deviation on a Facility ☐ uncontrolled loss of firm load ☐ System separation (islanding) ☐ Generation loss ☐ IBR generation loss ☐ Loss of DC Tie Line ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ Unplanned evacuation of its BES control center ☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	Written description (optional):

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
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3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	
4	February 9, 2017	Adopted by the NERC Board of Trustees	Revised
4	January 18, 2018	FERC order issued approving EOP-004-4. Docket No. RM17-12-000	
5	TBD	Adopted by the NERC Board of Trustees	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 7 – March 8, 2023

Anticipated Actions	Date
45-day formal or informal comment period with ballot	July to September 2023
45-day formal or informal comment period with additional ballot	December 2023 to January 2024
45-day final ballot	February 2024
Board adoption	May 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-~~004-4~~**004-5**
3. **Purpose:** To improve the reliability of the Bulk Electric System **(BES)** by requiring the reporting of events by Responsible Entities.
4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following Functional Entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-~~004-4~~**004-5**.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-~~004-4~~**004-5** Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-~~004-4~~**004-5** Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-~~004-4~~**004-5** Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations*

Assessment]

M2. Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-~~004-4~~004-5 Attachment 2 form or a ~~DOE-OE~~DOE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

~~If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all~~

~~requested and submitted subsequent audit records.~~

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 48 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the end of the next business day, as applicable.	the end of the next business day, as applicable.	end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

~~Link~~**Link** to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written event report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or ~~DOE-OE~~DOE-417 form) pursuant to Requirements R1 and R2.

~~**Rationale for Attachment 1:**~~

~~System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.~~

~~Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."~~

~~Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.~~

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction resulting from a BES Emergency	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction resulting from a BES Emergency	TOP	System-wide voltage reduction of 3% or more.
Firm load ~~sheddingresulting~~**shedding resulting** from a BES Emergency	Initiating RC, BA, or TOP	Firm load shedding ≥ 100 MW (manual or automatic).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of =/> 10% of nominal voltage sustained for ≥ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for ≥ 15 minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA	Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.
IBR generation loss	**BA**	**Total aggregated generation loss of ≥ 500 MW from inverter-based resource(s) (IBR)[1] occurring within a 30 second**

[1] For the purposes of EOP-004-5, an IBR is a generation resource consisting of one or more IBR unit(s) that connect to the transmission or subtransmission system via a single point of connection. An IBR unit is a primary energy source containing an individual inverter device, individual converter device, or a grouping of multiple inverters/converters. IBR units

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
		period. IBR generation loss shall be calculated using Telemetering data[2] by subtracting the lowest aggregated IBR generation output observed during a 30 second period from the pre-disturbance aggregated IBR generation output.
Loss of DC Tie Line	BA	Loss of a DC Tie Line, between two separate asynchronous systems, loaded at ≥ 500 MW.

of connection. An IBR unit is a primary energy source containing an individual inverter device, individual converter device, or a grouping of multiple inverters/converters. IBR units include solar photovoltaic, Type 3 and Type 4 wind, battery energy storage, high voltage direct current (HVDC) transmission, and dynamic reactive devices such as static synchronous compensators (STATCOMs) and static VAR compensators (SVCs).

[2] Indicated IBR generation loss due to a failure of SCADA or Telemetering data is not reportable under this requirement.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE-~~OE~~-417 form in lieu of this form, if the entity is required to submit ~~an OE~~a DOE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446- 9780, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No ☐ Unknown ☐
4.	**Event Identification and Description:**	
	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical threat to its Facility ☐ Physical threat to its BES control center ☐ BES Emergency: ☐ firm load shedding ☐ public appeal for load reduction ☐ System-wide voltage reduction ☐ voltage deviation on a Facility ☐ uncontrolled loss of firm load ☐ System separation (islanding) ☐ Generation loss ☐ **IBR generation loss** ☐ **Loss of DC Tie Line** ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ Unplanned evacuation of its BES control center ☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	Written description (optional):

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	
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4	January 18, 2018	FERC order issued approving EOP-004-4. Docket No. RM17-12-000	
5	TBD	Adopted by the NERC Board of Trustees	

~~Guideline and Technical Basis~~

~~Multiple Reports for a Single Organization~~

~~For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.~~

~~Law Enforcement Reporting~~

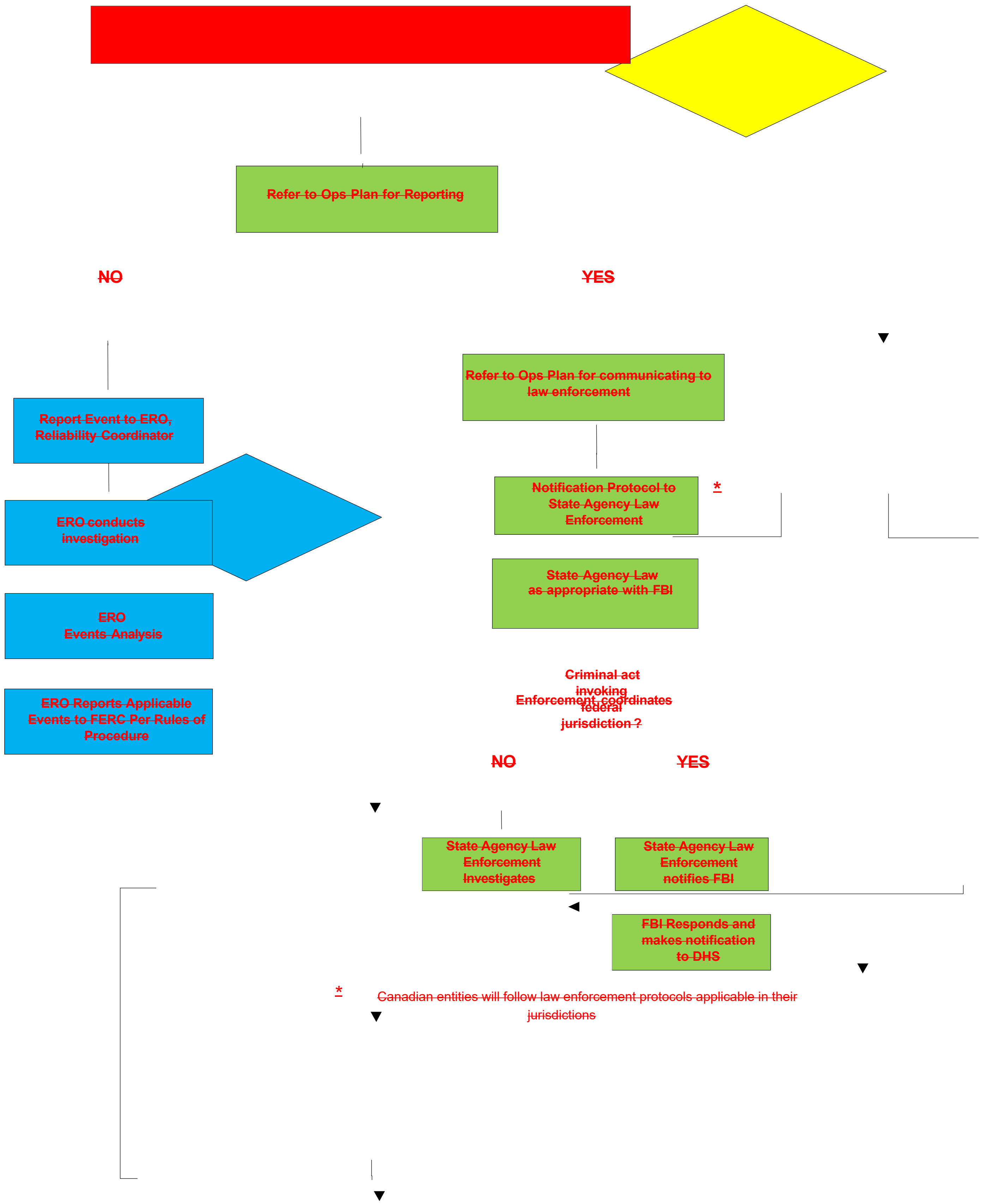
~~The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.~~

~~Stakeholders in the Reporting Process~~

- ~~Industry~~
- ~~NERC (ERO), Regional Entity~~
- ~~FERC~~
- ~~DOE~~
- ~~NRC~~
- ~~DHS – Federal~~
- ~~Homeland Security- State~~
- ~~State Regulators~~
- ~~Local Law Enforcement~~
- ~~State or Provincial Law Enforcement~~
- ~~FBI~~
- ~~Royal Canadian Mounted Police (RCMP)~~

~~The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.~~

~~Example of Reporting Process including Law Enforcement~~



* ~~Canadian entities will follow law enforcement protocols applicable in their jurisdictions~~

~~Potential Uses of Reportable Information~~

~~General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional Entities to report the incidents and provide information known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.~~

Implementation Plan

Project 2023-01 EOP-004 IBR Event Reporting
Reliability Standard EOP-004-5

Applicable Standard(s)

- EOP-004-5 Event Reporting

Requested Retirement(s)

- EOP-004-4 Event Reporting

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Transmission Operator
- Generator Owner
- Generator Operator
- Distribution Provider

New/Modified/Retired Terms in the NERC Glossary of Terms

- None

Background

Following multiple widespread solar PV loss events, NERC published the San Fernando disturbance report[1] in November 2020, which identified a set of recommendations for industry. The NERC IRPS performed a follow-up analysis to identify any actions needed to address the recommendations laid out by NERC. One of the recommendations was for IRPS to draft a SAR to address the issue identified in EOP-004 regarding the generation loss criteria so that the reporting criteria will capture inverter-based resource (IBR) events as well synchronous generation. The thresholds for generation loss

[1] https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf

reporting in EOP-004-4 are relatively large and more suitable for synchronous generation. They are not aligned with the past large scale IBR disturbances analyzed by the ERO, which caused widespread grid disturbances but were not required to be reported as they did not meet the EOP-004 thresholds.

The revised Project 2023-01 EOP-004 IBR Event Reporting Standard Authorization Request (SAR) was accepted by the standards committee on May 17, 2023. The Reliability Standard revisions proposed by this project will help enhance the reliability of the Bulk Power System by ensuring timely reporting of events involving IBRs to the ERO. The new reporting criteria thresholds for IBR are tailored to the nature of IBR events and will ultimately lead to a more rapid response to widespread IBR losses and improved generation performance.

General Considerations

This implementation plan provides that entities shall have twenty-four (24) months to become compliant with the revised Reliability Standard. This implementation plan reflects consideration that entities will need time to revise their event reporting Operating Plan and related procedures to include the new event types under Reliability Standard EOP-004-5 Attachment 1. Particular consideration has also been given to the fact that not all Balancing Authorities that will have reporting responsibilities for the two new added criteria currently possess the capability of timely detection of a loss of IBRs at the threshold specified in the revised standard. A twenty-four (24) month implementation period reflects the needs of these entities to revise data specifications and create additional SCADA tags, and for the asset owners and operators in their balancing areas to be able to submit the additional data. The implementation plan reflects the fact that data will need to be incorporated into networking models, possibly necessitating custom vendor solutions. New calculations and alarming criteria will need to be created to alert staff that the threshold for IBR loss has been reached as well as additional log files created to support analysis.

Effective Date

Reliability Standard EOP-004-5

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority’s order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard EOP-004-4

Reliability Standard EOP-004-4 shall be retired immediately prior to the effective date of EOP-004-5 in the particular jurisdiction in which the revised standard is becoming effective.

Project 2022-01 Reporting ACE Definition and Associated Terms

Action

Authorize initial posting of the proposed ACE Diversity Interchange definition for a 45-day formal comment period, with ballot pools formed in the first 30 days, and parallel initial ballots conducted during the last 10 days of the comment period.

Background

The primary purpose of this project is to address the recommendation of the NERC Reliability and Security Technical Committee Resources Subcommittee that the definition of Reporting ACE be revised to improve long-term average frequency performance and provide other Interconnections the ability to pursue automatic correction approaches.

The Standards Committee (SC) originally accepted the Standards Authorization Request (SAR) on Jan 19, 2022. The SC accepted the revised SAR, authorized drafting revisions, and appointed the SAR DT to the standards drafting team (SDT) at the June 15, 2022 SC meeting. The SDT met several times to consider revisions to the Reporting ACE definition and related definitions and terms. On January 25, 2023 the SC authorized the first posting for this project. The SDT proposes to add one new term, revise several existing terms, and retire terms that are or would no longer be used in any Reliability Standard or Glossary definition.

Summary

During the initial ballot, all proposed terms received the required industry approval. However, based on responses to questions posed during the comment period, the majority of commenters expressed a preference for a newly defined term, ACE Diversity Interchange (ADI). After considering the comments received, the SDT voted in favor of proposing a new defined term, ACE Diversity Interchange (ADI), for inclusion in the NERC Glossary. Additionally, the term Reporting ACE is revised to reference the proposed newly defined term; this term will be posted for a second 45-day formal comment period and ballot to accompany the proposed definition of ADI.

NERC staff recommends that the SC authorize an initial 45-day comment period and ballot for the proposed term, ACE Diversity Interchange Definition (ADI). This will require the creation of separate ballot pools, consistent with the balloting process for this project to date in which each term has a distinct ballot pool.

ACE Definition

Project 2022-01 Reporting ACE Definition and Associated Terms
Draft 1

The standard drafting team (SDT) is seeking comments on the following new or modified terms used in the proposed standards. The first column (*NERC Glossary Term*) provides the NERC Glossary term being modified or proposed as a new. AS SHOWN IN REDLINE, the SDT is proposing acronyms to some currently approved new Glossary terms. The second column (*Currently Approved Definition*) provides the currently approved definition and the third column (*SDT Proposed New or Revised)* reflects the proposed modifications to the current definitions in redline and also reflects newly proposed definitions in clean view. The fourth column identifies the currently effective Reliability Standards or *Glossary* terms used in the proposed terms.

Table 1: Retired, Modified, or Newly Proposed Definitions

NERC Glossary Term	Currently Approved Definition	SDT Proposed New or Revised REDLINE TO Currently Approved	Standards Effected / Definitions Affected	Technical Guidelines / Reference Documents	Notes
ACE Diversity Interchange (ADI)		A frequency neutral exchange program where multiple participating Balancing Authorities utilize it to achieve reductions in their generation control and Reporting ACE through offsets to either Actual Net Interchange or Scheduled Net Interchange ACE components to create an ACE value closer to zero for each participant.	Included in the revised Reporting ACE definition that will be re-balloted concurrently.		New defintion

ACE Definition

Project 2022-01 Reporting ACE Definition and Associated Terms
Draft 1

The standard drafting team (SDT) is seeking comments on the following new or modified terms used in the proposed standards. The first column (*NERC Glossary Term*) provides the NERC Glossary term being modified or proposed as a new. AS SHOWN IN REDLINE, the SDT is proposing acronyms to some currently approved new Glossary terms. The second column (*Currently Approved Definition*) provides the currently approved definition and the third column (*SDT Proposed New or Revised)* reflects the proposed modifications to the current definitions in redline and also reflects newly proposed definitions in clean view. The fourth column identifies the currently effective Reliability Standards or *Glossary* terms used in the proposed terms.

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Project 2021-04 Modifications to PRC-002-4

Action

Authorize initial posting of proposed new Reliability Standard PRC-028-1 and modification of Reliability Standard PRC-002-5 and the associated Implementation Plan for a 45-day formal comment period, with ballot pools formed in the first 30 days, and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

Background

The Project 2021-04 drafting team (DT) was charged with addressing two Standard Authorization Requests (SARs) related to PRC-002, to be addressed in two separate phases. The first SAR was submitted by Glencoe Light who sought clarification of notifications and data requirements. The second SAR was submitted by the NERC Inverter-based Resource Performance Task Force (IRPTF). In its March 2020 white paper, "IRPTF Review of NERC Reliability Standards White Paper," the IRPTF identified issues with PRC-002-2 that should be addressed.

At the Standards Committee (SC) January 20, 2021 meeting, the SC accepted both PRC-002 SARs referenced above and authorized soliciting for members for the SAR DT. At the September 23, 2021 meeting, the SC appointed chair, vice chair, and members to the Project 2021-04 Modifications to PRC-002 SAR DT. At its January 19, 2022 meeting, the SC accepted the revised SARs; authorized drafting revisions to the Reliability Standards identified in the SARs; and appointed the SAR DT as the project DT.

The DT completed the first phase of work to address the Glencoe Light SAR in winter 2023 with the development of Reliability Standard PRC-002-4.

After much debate, the DT strongly believes that to address the needs identified in the IRPTF SAR, a new standard for monitoring requirements for IBRs should be created instead of revising PRC-002. As such, the DT submitted a revised SAR for SC approval on April 19, 2023. At that meeting, SC authorized drafting revisions to the Reliability Standards identified in the SAR, i.e., to create a new standard (PRC-028-1) to address needs identified in the IRPTF SAR and to make minor revisions to PRC-002 as necessary to align with the new standard.

Summary

The Project 2021-04b DT seeks authorization to post the proposed new Reliability Standard PRC-028-1 and proposed modified Reliability Standard PRC-002-5 for comment and ballot.

The Quality Review (QR) for this posting was performed from June 6, 2023 - June 16, 2023. The QR team members from NERC are Lauren Perotti, Jon Hoffman, Scott Barfield, Ryan Mauldin, Teri Stasko, Latrice Harkness, Alison Oswald, and Ryan Quint. The SDT also reached out to the industry for additional QR. The QR members from the industry included Charles Yeung (SPP), Mike Brytowski (GREnergy), Bobbi Hartwell (BPA), Rodney Hendrickson (BPA), and Dmitry Anichkov (Meritsi Company).

The SDT reviewed all QR comments and revised the proposed Reliability Standard and Implementation Plan where appropriate.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal comment period with ballot	08/01/2023 – 09/15/2023
45-day formal or informal comment period with additional ballot	11/01/2023 – 12/15/2023
10-day final ballot	TBD
Board adoption	TBD

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-5
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
   - **4.2. Facilities:** BES Elements, excluding inverter-based portions of generating plants/Facilities meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition.[1]
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-5, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[2] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-5, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

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[1] Disturbance monitoring and reporting requirements for inverter-based resources are addressed in PRC-028.

[2] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns directly connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Phase-to-neutral voltage for each phase of each specified BES bus.

3.2. Each phase current and the residual or neutral current for the following BES Elements:

3.2.1. Transformers that have a low-side operating voltage of 100 kV or above.

3.2.2. Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2. A minimum recording rate of 16 samples per cycle.

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1. Synchronous machine based generating resource(s) with:

5.1.1.1. Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2. Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2. Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3. Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5. Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2. Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1. One BES Element; and

5.2.2. One BES Element per 3,000 MW of the Reliability Coordinator’s historical simultaneous peak System Demand.

5.3. Notify all owners of identified BES Elements, within 90 calendar days of completion of Part 5.1, that their respective BES Elements require DDR data.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part

5.3. Evidence may include, but is not limited to letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. One phase-to-neutral or positive sequence voltage.

6.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of the Reliability

Standard PRC-002-2[3] and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	>0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES

[3] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or (3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.

11.3. SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1)

dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

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

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, for five calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12, for three calendar years.

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	20 calendar days, but less than or equal to 30 calendar days.	
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent, but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent, but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent, but less than 100 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by 30 calendar days or less.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent, but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 30 calendar	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent, but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 60 calendar days and less	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 90 calendar days.

			OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent, but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent, but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent, but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60

			than 100 percent of the total recording properties as specified in Requirement R9.	equal to 80 percent of the total recording properties as specified in Requirement R9.	than or equal to 70 percent of the total recording properties as specified in Requirement R9.	percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent, but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent, but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent, but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority.

			extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days

			calendar days after discovery of the failure.	days after discovery of the failure.	calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

					than or equal to 12 months.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-5: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-5: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC approved PRC-002-4. Docket No. RD23-4-000	Revised under Project 2021-04
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for SER and FR data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of Bulk Electric System (BES) buses that it owns. Refer to section 4.2 Facilities for exclusion.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three-phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three-phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three-phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete, and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three-phase short circuit MVA of the newly identified BES bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

<u>If the list has more than 11 BES buses:</u> SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three-phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other Disturbance Monitoring Equipment (DME) devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[4]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[4] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal comment period with ballot	08/01/2023 – 09/15/2023
45-day formal or informal comment period with additional ballot	11/01/2023 – 12/15/2023
10-day final ballot	TBD
Board adoption	TBD

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-~~5~~4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
   - **4.2. Facilities:** BES Elements, excluding inverter-based portions of generating plants/Facilities meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition.[1]
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-~~5~~4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[2] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-~~5~~4, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

[1] Disturbance monitoring and reporting requirements for inverter-based resources are addressed in PRC-028.

[2] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns directly connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Phase-to-neutral voltage for each phase of each specified BES bus.

3.2. Each phase current and the residual or neutral current for the following BES Elements:

3.2.1. Transformers that have a low-side operating voltage of 100 kV or above.

3.2.2. Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2. A minimum recording rate of 16 samples per cycle.

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1. Synchronous machine based ~~G~~generating resource(s) with:

5.1.1.1. Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2. Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2. Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3. Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5. Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2. Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1. One BES Element; and

5.2.2. One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3. Notify all owners of identified BES Elements, within 90 calendar days of completion of Part 5.1, that their respective BES Elements require DDR data.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part

5.3. Evidence may include, but is not limited to~~:~~ letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. One phase-to-neutral or positive sequence voltage.

6.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3. Real Power and Reactive Power flows expressed on a three~~-~~-phase basis corresponding to all circuits where current measurements are required.

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3. Real Power and Reactive Power flows expressed on a three~~-~~-phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of the Reliability

Standard PRC-002-2[3] and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	>0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES

[3] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.

11.3. SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1)

dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. ~~Data~~Evidence Retention:

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

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, ~~Measure M1~~ for five calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, ~~Measure M5~~ for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, ~~Measure M6~~ for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, ~~Measure M7~~

for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of ~~requested data provided as per~~ Requirements R2, R3, R4, R8, R9, R10, R11, and R12, ~~Measures M2, M3, M4, M8, M9, M10, M11, and M12~~ for three calendar years.

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, ~~Measure 13~~ for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non- compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	20 calendar days, but less than or equal to 30 calendar days.	
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent, but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent, but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters~~properties~~ as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters~~properties~~ as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters~~properties~~ as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters~~properties~~ as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent, but less than 100 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent, but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 30 calendar	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent, but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 60	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but

			was late by 30 calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	calendar days and less than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	was late by greater than 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner ~~failed to~~ hadve DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical

			quantities for each BES Element~~for all applicable BES Elements~~.	Element ~~for all applicable BES Elements~~.	quantities for each BES Element ~~for all applicable BES Elements~~.	quantities for each BES Element.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is ~~-~~the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element~~for all applicable BES Elements~~.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element ~~for all applicable BES Elements~~.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element ~~for all applicable BES Elements~~.	The Generator Owner ~~failed to~~ had~~ve~~ DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent, but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent, but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent, but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent, but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent, but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent, but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide the requested data more than 60

			less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to

			Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	the Regional Entity more than 120 calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part

				and was late by less than or equal to 6 months.	5.4 and was late by greater than 6 months but less than or equal to 12 months.	5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-~~5~~4: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-~~5~~4: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC approved PRC-002-4. Docket No. RD23-4-000	Revised under Project 2021-04
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for ~~sequence of events recording (~~SER~~)~~ and ~~Fault recording (~~FR~~)~~ data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of Bulk Electric System (BES) buses that it owns. Refer to section 4.2 Facilities for exclusion.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three-phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three-phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three-phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete, and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three-phase short circuit MVA of the newly identified BES bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three~~-~~-phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other Disturbance Monitoring Equipment (DME) devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[4]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[4] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	
Requirement	**Entity**	**Identify BES Elements**	**Notification**	**DDR**	**5 Year Re-evaluation**	
R5	RC	X	X	X	X	
R6	TO			X		
R7	GO			X		
R8	TO | GO			X		
R9	TO | GO			X		
Requirement	**Entity**	**Time Synchronization**	**Provide SER, FR, DDR Data**	**SER, FR, DDR Availability**		
R10	TO | GO	X				
R11	TO | GO		X			
R12	TO | GO			X		
Requirement	**Entity**	**Implementation**				
R13	TO | GO	X				

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021
Standards Committee approved revised Standard Authorization Request (SAR) for creating a new Standard	4/19/2023

Anticipated Actions	Date
45-day formal comment period with ballot	08/01/2023 – 09/15/2023
45-day formal or informal comment period with additional ballot	11/01/2023 – 12/15/2023
10-day final ballot	TBD
Board adoption	TBD

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
2. **Number:** PRC-028-1
3. **Purpose:** To have adequate data available from inverter-based resources (IBR) to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Owner that owns equipment as identified in section 4.2
     - **4.1.2.** Generator Owner that owns equipment as identified in section 4.2
   - **4.2. Facilities:** The following Elements associated with BES generating plants (inverter-based portion of generating plant/Facility meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition):
     - **4.2.1** Circuit breaker(s).
     - **4.2.2** Main power transformer(s)[1].
     - **4.2.3** Collector bus.
     - **4.2.4** Shunt static or dynamic reactive device(s).
     - **4.2.5** At least one IBR unit[2] connected to last 10% of each collector feeder length (i.e., furthest from the collector bus).
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner and Generator Owner shall have sequence of event recording (SER) data for the following Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- **1.1.** Circuit breaker position (open/close) for circuit breakers associated with the Elements identified in section 4.2.
- **1.2.** At least one IBR unit connected to last 10% of each collector feeder length. IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded.
  - **1.2.1.** All fault codes.

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[1] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.

[2] IBR unit includes the inverter, converter, wind turbine generator, or high voltage direct current converter connecting generating resource to alternating current Transmission network.

1.2.2. All fault alarms.

1.2.3. Change of operating mode.

1.2.4. High and low voltage ride-through.

1.2.5. High and low frequency ride-through.

1.2.6. Control system command values, reference values, and feedback signals.

M1. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1. Evidence may include, but is not limited to: (1) actual data recordings; or (2) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R2. Each Transmission Owner and Generator Owner shall have triggered fault recording (FR) data to determine the following electrical quantities for Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. High-side of the main power transformer FR data:

2.1.1. Phase-to-neutral voltage for each phase.

2.1.2. Each phase current and the residual or neutral current.

2.1.3. Real and Reactive Power.

2.2. IBR unit FR data from at least one IBR unit connected to last 10% of each collector feeder length:

2.2.1. Each AC phase-to-neutral or phase-to-phase voltage, as applicable, at IBR unit terminals or on high-side of the IBR unit transformer.

2.2.2. Each AC phase current and the residual or neutral current, as applicable, on IBR unit terminals or on high-side of the IBR unit transformer.

2.2.3. DC bus current and voltage. IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded.

2.3. Dynamic reactive device

2.3.1. Phase-to-neutral voltage for each phase.

2.3.2. Each phase current and the residual or neutral current.

2.3.3. Real and Reactive Power output.

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R2. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R2 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. High-side of the main power transformer FR data

3.1.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.1.2. A minimum recording rate of 128 samples per cycle.

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

3.2. IBR unit level data

3.2.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2 seconds for the same trigger point.

3.2.2. A minimum recording rate of 128 samples per cycle.

3.2.3. Trigger settings for at least the following:

3.2.3.1. AC Phase overvoltage and undervoltage.

3.2.3.2. DC overvoltage, DC overcurrent, and DC reverse current.

3.2.3.3. Overfrequency and underfrequency.

3.3. Dynamic reactive device FR data

3.3.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.3.2. A minimum recording rate of 128 samples per cycle.

3.3.3. Trigger settings for at least the following:

3.3.3.1. Neutral (residual) overcurrent.

3.3.3.2. AC phase overvoltage and undervoltage.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R3. Evidence may include, but is not limited to: (1) actual data recordings or derivations, or (2) documents describing the device specification and device configuration or settings.

R4. Each Generator Owner and Transmission Owner shall have continuous dynamic Disturbance recording (DDR) data and storage to determine the following electrical quantities for each main power transformer(s) it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. One phase-to-neutral or positive sequence voltage on high-side of the main power transformer(s).

4.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R4, Part 4.1, or the positive sequence current.

4.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to each main power transformer(s) where current measurements are required.

4.4. Frequency of any one of the voltage(s) in Requirement R4, Part 4.1.

M4. The Generator Owner or Transmission Owner has evidence (electronic or hard copy) of continuous DDR data recording and storage to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (3) station drawings.

R5. Each Transmission Owner and Generator Owner responsible for DDR data for the electrical quantities identified in Requirement R4 shall meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Input sampling rate of at least 960 samples per second.

5.2. Output recording rate of electrical quantities of at least 60 times per second.

M5. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R5. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R5, Part 5.1; R5, Part 5.2); or (2) actual data recordings (R5, Part 5.2).

R6. Each Transmission Owner and Generator Owner shall time synchronize all SER, FR, and DDR data to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

6.2. Synchronized device clock accuracy within ± 100 microseconds of UTC.

M6. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R7. Each Transmission Owner and Generator Owner shall provide, upon request, all SER, FR, and DDR data to its Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Data shall be retrievable for the period of 30 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within 30 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII[3] Comma Separated Value (CSV) format following Attachment 1.

7.4. FR and DDR data shall be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard Common Format for Transient Data Exchange (COMTRADE)), revision C37.111-1999 or later.

7.5. Data files shall be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M7. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R7. Evidence may include, but is not limited to: (1) actual data recordings; (2) dated transmittals to the requesting entity with formatted records; or (3) documents describing data storage capability, device specification, configuration, or settings.

R8. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR, or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M8. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R8. Evidence may include, but is not limited to: (1) dated reports of the discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated Corrective Action Plan transmittals to the Regional Entity and evidence of Corrective Action Plan implementation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

[3] American Standard Code for Information Exchange.

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

The Transmission Owner and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner and Generator Owner shall retain evidence, as per Requirements R1 through R8, for three calendar years.

If a Transmission Owner or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent but less than or equal to 70 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.
R2	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical

			quantities for each Element.	quantities for each Element.	quantities for each Element.	quantities for each Element.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

R5	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.
R6	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.
R7	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as

			directed by Requirement R7, Part 7.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	directed by Requirement R7, Part 7.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	directed by Requirement R7, Part 7.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	directed by Requirement R7, Part 7.2 failed to provide the requested data more than 60 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided less than or equal to 70 percent of the data in the proper data format.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and failed to provide a Corrective Action Plan to the Regional Entity more than 120

			calendar days after discovery of the failure.	days after discovery of the failure.	calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-028-1: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011: IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

IEEE Std 2800-2022: IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.

Multiple Solar PV Disturbances in CAISO, Joint NERC and WECC Staff Report, April 2022.

NERC Reliability Standard PRC-002-5.

Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021, Joint NERC and Texas RE Event Report, September 2021.

Odessa Disturbance, Texas Event: June 4, 2022, Joint NERC and Texas RE Event Report, December 2022.

Version History

Version	Date	Action	Change Tracking
0	TBD	Adopted by NERC Board of Trustees	New

Attachment 1

Sequence of Events Recording (SER) Data Format

(Requirement R7, Part 7.3)

Date, Time, Local Time Code, Plant Name, Device[4], State[5]

08/27/23, 23:58:57.110, -5, Plant name 1, Breaker 1, Close

08/27/23, 23:58:57.082, -5, Plant name 2, Breaker 2, Close

08/27/23, 23:58:47.217, -5, Plant name 1, IBR unit 1, Open

08/27/23, 23:58:47.214, -5, Plant name 2, IBR unit 2, Open

08/27/23, 23:58:47.217, -5, Plant name 1, IBR unit 1, undervoltage ride-through mode

08/27/23, 23:58:47.214, -5, Plant name 2, IBR unit 2, dc overcurrent trip

[4] Device name may include specific names of breakers or IBR units as appropriate.

[5] Breaker status and any other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is acceptable. For IBR unit level data, fault codes, alarms, change in operating mode etc. are also acceptable.

Implementation Plan

Project 2021-04
Reliability Standards PRC-002-5 and PRC-028-1

Applicable Standard(s)

- PRC-002-5 Disturbance Monitoring and Reporting Requirements
- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

Requested Retirement(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner (TO)
- Generator Owner (GO)

General Considerations

Additional time to implement Reliability Standard PRC-002-5 is not provided because the revisions are clarifying in nature to exclude inverter-based resources from PRC-002 applicability as they are included in PRC-028. The revision to PRC-002 does not require any procurement or installation of disturbance monitoring equipment.

The Reliability Standard PRC-028-1 is expected to have wide ranging impact on TOs and GOs as many existing and new facilities would be required to have disturbance monitoring equipment. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities. The Implementation Plan takes into account scheduling outages needed to implement sequence of events recording, fault recording, and dynamic disturbance recording capability. An entity owning only one (1) identified generating plant/Facility is allowed three (3) calendar years for implementation to accommodate normal outage schedules. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities.

Effective Date of PRC-002-5

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-002-5 shall become effective on the later of: (1) the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority; or (2) the effective date of PRC-002-4.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-002-5 shall become effective on the later of: (1) the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction; or (2) the effective date of PRC-002-4.

Effective Date of PRC-028-1 and Phased-in Compliance Dates

The effective date for proposed Reliability Standard PRC-028-1 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard PRC-028-1

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance Date for PRC-028-1 Requirements R1-R7

Entities shall be fully compliant at 50 percent of their generating plants/Facilities within three (3) calendar years of the effective date of PRC-028-1 and fully compliant at 100% of their generating plant/Facilities within five (5) calendar years of the effective date of Reliability Standard PRC-028-1.

Entities that are required to monitor only one (1) generating plant/Facility shall be fully compliant within three (3) calendar years of the effective date of Reliability Standard PRC-028-1.

Entities with more than one (1) generating plant/Facility are encouraged to develop a strategy, to be shared with ERO Compliance Monitoring and Enforcement Program staff as requested, for how they will implement Reliability Standard PRC-028-1 across their generating fleet.

Compliance Date for PRC-028-1 Requirement R8

Entities shall be 100% compliant on the first day of the first calendar quarter nine (9) months after the effective date of Reliability Standard PRC-028-1.

Retirement Date

The Reliability Standard PRC-002-4 shall be retired immediately prior to the effective date of Reliability Standard PRC-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

Prior Implementation Plan

The following element of the Implementation Plan for PRC-002-4 is incorporated herein and modified in case PRC-002-4 is superseded by PRC-002-5 prior to becoming effective:

Reliability Coordinators in the Eastern Interconnection shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-4 or six (6) months of the effective date of PRC-002-5, whichever occurs first.

NERC Legal and Regulatory Update – Reliability Standards
June 6, 2023 – July 5, 2023

NERC FILINGS TO FERC SUBMITTED SINCE LAST SC UPDATE

FERC Docket No.	Filing Description	FERC Submittal Date
EL23-69-000	Motion to Intervene and Comments in Opposition to Petition for Rulemaking NERC submitted a Motion to Intervene and Comments in Opposition to the Petition for Rulemaking to Require Enhanced Standard for Determining Critical Infrastructure, Using Engineering Models to Define Critical Infrastructure Assets to be Subject to Enhanced Protection filed by the Secure-the-Grid Coalition.	6/13/2023
RR23-1-000	Reply Comments to Public Citizen, Inc. NERC submitted reply comments to comments of Public Citizen, Inc. regarding the Petition for Approval of Revisions to the Texas RE Regional Reliability Standards Process (RSDP).	6/15/2023
RD20-2-000	CIP SDT Schedule June Update Informational Filing NERC submitted an informational filing as directed by FERC in its February 20, 2020 Order. This filing contains a status update on one standard development project relating to the CIP Reliability Standards.	6/15/2023

FERC ISSUANCES SINCE LAST SC UPDATE

FERC Docket No.	Issuance Description	FERC Issuance Date
RM22-10-000	Final Rule on Transmission System Planning Performance Requirements for Extreme Weather FERC issued a Final Rule directing NERC to develop a new Reliability Standard or modifications to TPL-001-5.1 that addresses concerns pertaining to transmission system planning for extreme weather within 18 months of publication of the Final Rule in the Federal Register.	6/15/2023
RD23-1-001	Order Addressing Arguments Raised on Rehearing FERC issues an order addressing arguments raised on rehearing regarding Extreme Cold Weather Reliability Standards (EOP-011-3 and EOP-012-1) approved by FERC on February 16, 2023.	6/29/2023

ANTICIPATED UPCOMING FILINGS

FERC Docket No.	Filing Description	Anticipated Filing Date
	None	

Standards Committee Expectations

Approved by Standards Committee January 12, 2012

Background

Standards Committee (SC) members are elected by members of their segment of the Registered Ballot Body, to help the SC fulfill its purpose. According to the Standards Committee Charter, the SC's purpose is:

> *In compliance with the NERC Reliability Standards Development Procedure, the Standards Committee manages the NERC standards development process for the North American-wide reliability standards with the support of the NERC staff to achieve broad bulk power system reliability goals for the industry. The Standards Committee protects the integrity and credibility of the standards development process.*

The purpose of this document is to outline the key considerations that each member of the SC must make in fulfilling his or her duties. Each member is accountable to the members of the Segment that elected them, other members of the SC, and the NERC Board of Trustees for carrying out their responsibilities in accordance with this document.

Expectations of Standards Committee Members

1. SC members represent their segment, not their organization or personal views. Each member is expected to identify and use mechanisms for being in contact with members of the segment in order to maintain a current perspective of the views, concerns, and input from that segment. NERC can provide mechanisms to support communications if an SC member requests such assistance.
2. SC members base their decisions on what is best for reliability and must consider not only what is best for their segment, but also what is in the best interest of the broader industry and reliability.
3. SC members should make every effort to attend scheduled meetings, and when not available are required to identify and brief a proxy from the same segment. SC business cannot be conducted in the absence of a quorum, and it is essential that each SC member make a commitment to being present.
4. SC members should not leverage or attempt to leverage their position on the SC to influence the outcome of standards projects.
5. The role of the SC is to manage the standards process and the quality of the output, not the technical content of standards.

Parliamentary Procedures

Based on Robert's Rules of Order, Newly Revised, 11th Edition, plus "Organization and Procedures Manual for the NERC Standing Committees"

Motions

Unless noted otherwise, all procedures require a "second" to enable discussion.

When you want to…	Procedure	Debatable	Comments
Raise an issue for discussion	Move	Yes	The main action that begins a debate.
Revise a Motion currently under discussion	Amend	Yes	Takes precedence over discussion of main motion. Motions to amend an amendment are allowed, but not any further. The amendment must be germane to the main motion, and cannot reverse the intent of the main motion.
Reconsider a Motion already approved	Reconsider	Yes	Allowed only by member who voted on the prevailing side of the original motion.
End debate	Call for the Question *or* End Debate	No	If the Chair senses that the committee is ready to vote, he may say "if there are no objections, we will now vote on the Motion." The vote is subject to a 2/3 majority approval. Also, any member may call the question. This motion is not debatable. The vote is subject to a 2/3 vote.
Record each member's vote on a Motion	Request a Roll Call Vote	No	Takes precedence over main motion. No debate allowed, but the members must approve by 2/3 majority.
Postpone discussion until later in the meeting	Lay on the Table	Yes	Takes precedence over main motion. Used only to postpone discussion until later in the meeting.
Postpone discussion until a future date	Postpone until	Yes	Takes precedence over main motion. Debatable only regarding the date (and time) at which to bring the Motion back for further discussion.
Remove the motion for any further consideration	Postpone indefinitely	Yes	Takes precedence over main motion. Debate can extend to the discussion of the main motion. If approved, it effectively "kills" the motion. Useful for disposing of a badly chosen motion that can not be adopted or rejected without undesirable consequences.
Request a review of procedure	Point of order	No	Second not required. The Chair or secretary shall review the parliamentary procedure used during the discussion of the Motion.

Notes on Motions

Seconds. A Motion must have a second to ensure that at least two members wish to discuss the issue. The “seconder” is not recorded in the minutes. Neither are motions that do not receive a second.

Announcement by the Chair. The Chair should announce the Motion before debate begins. This ensures that the wording is understood by the membership. Once the Motion is announced and seconded, the Committee “owns” the motion, and must deal with it according to parliamentary procedure.

Voting

Voting Method	When Used	How Recorded in Minutes
Unanimous Consent The standard practice.	When the Chair senses that the Committee is substantially in agreement, and the Motion needed little or no debate. No actual vote is taken.	The minutes show "by unanimous consent."
Vote by Voice	The standard practice.	The minutes show Approved or Not Approved (or Failed).
Vote by Show of Hands (tally)	To record the number of votes on each side when an issue has engendered substantial debate or appears to be divisive. Also used when a Voice Vote is inconclusive. (The Chair should ask for a Vote by Show of Hands when requested by a member).	The minutes show both vote totals, and then Approved or Not Approved (or Failed).
Vote by Roll Call	To record each member's vote. Each member is called upon by the Secretary, and the member indicates either "Yes," "No," or "Present" if abstaining.	The minutes will include the list of members, how each voted or abstained, and the vote totals. Those members for which a "Yes," "No," or "Present" is not shown are considered absent for the vote.