NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

November 3, 2023

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: *Petition for Approval of Proposed Reliability Standard PRC-023-6*
Docket No. RD23-5-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby provides amended petition for approval of proposed Reliability Standard PRC-023-6, first filed in the above-captioned docket on March 2, 2023.[1] On October 10, 2023, the Office of Electric Reliability issued a letter seeking additional information regarding NERC's proposed retirement of Requirement R2 of the currently effective PRC-023 standard.[2]

As detailed in the amended petition, Requirement R2 of PRC-023 is redundant to the protections already provided by Requirement R1, and is also duplicative of similar requirements in other Reliability Standards such as PRC-027-1 Requirement R2 (which was developed after PRC-023 Requirement R2). A detailed justification can be found in Section IV.A. of the amended petition.

NERC appreciates the opportunity to provide additional information in support of the proposed retirement of Requirement R2 in proposed Reliability Standard PRC-023-6. Please refer to Section IV.A., especially pages 22-25, of the amended filing for additional information addressing the areas identified in the October 10, 2023 letter.

Sincerely,

Lauren A. Perotti
Assistant General Counsel

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1 *Petition of NERC for Approval of Proposed Reliability Standard PRC-023-6*, Docket No. RD23-5-000 (Mar. 2, 2023).
2 *N. Am. Elec. Reliability Corp.*, Docket No. RD23-5-000 (Oct. 10, 2023).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No.RD23-5-000**

AMENDED PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PRC-023-6

Lauren A. Perotti
Assistant General Counsel
North American Electric Reliability Corporation
1401 H Street NW Suite 410
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

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AMENDED PETITION OF THE
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FOR APPROVAL OF PROPOSED RELIABILITY STANDARD
PRC-023-6

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard PRC-023-6 (Transmission Relay Loadability). This amended petition supersedes the first petition filed by NERC in the above-captioned proceeding on March 2, 2023.[4]

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[1] 16 U.S.C. § 824o.

[2] 18 C.F.R. § 39.5 (2022).

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

[4] On October 10, 2023, the Director of the Commission's Office of Electric Reliability issued a request for additional information regarding NERC's proposal for approval of Reliability Standard PRC-023-6. Specifically, the request sought the following:

1. Explain how Requirement R2 is redundant to Requirement R1, i.e., the fault condition addressed by Requirement R2 is addressed by Requirement R1. In the explanation, identify the language in Requirement R1 that encompasses the Requirement R2 obligation to "set out-of-step-blocking elements to allow tripping of phase protective relays for faults that occur during loading conditions used to verify transmission line relay loadability."
2. Confirm whether, if Requirement R2 were to be retired, the existing obligations in Requirement R2 would be enforced and audited under Requirement R1.

The request stated that NERC should file a response within 30 days of the date of the letter by making an amendment filing in the above-captioned docket.

As discussed more fully herein, proposed Reliability Standard PRC-023-6 would advance the reliability of the Bulk-Power System ("BPS")[5] by retiring redundant and unnecessary language that has contributed to confusion regarding the proper application of the PRC-023 standard to out-of-step blocking[6] relays. NERC requests that the Commission approve the proposed Reliability Standard, as shown in **Exhibit A**, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests that the Commission approve: (i) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit E**), which are not substantively changed from the most recent approved version; (ii) the retirement of the version of the PRC-023 Reliability Standard that would then be in effect (i.e. currently effective Reliability Standard PRC-023-4 or the approved, but not yet effective Reliability Standard PRC-023-5); and (iii) the proposed implementation plan (**Exhibit B**).

As required by Section 39.5(a)[7] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed Reliability Standard, a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[8] (**Exhibit D**), and a summary of the standard development history (**Exhibit F**). The NERC Board of Trustees adopted the proposed Reliability Standard on February 16, 2023.

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5 Unless otherwise indicated, all capitalized terms shall have the meaning used in the *Glossary of Terms Used in NERC Reliability Standards*, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf [hereinafter NERC Glossary].

6 The term "power swing blocking" is also used to describe these elements. Except where quoted, the terms are used interchangeably in this filing.

7 18 C.F.R. § 39.5(a).

8 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104 at P 262, 321-37 [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

This petition is organized as follows: Section I provides a summary of NERC's petition. Section II provides the individuals to whom notices and communications related to the filing should be provided. Section III provides relevant background regarding: (i) the regulatory structure governing the Reliability Standards approval process; (ii) the history of the PRC-023 Reliability Standard; and (iii) information on the development process for the proposed Reliability Standard. Section IV provides an overview and justification for the proposed Reliability Standard. Section V provides a summary of the proposed implementation plan, and Section VI provides the conclusion.

I. OVERVIEW

Relay loadability refers to the ability of protective relays to restrain operation for load conditions. As protective relays can respond only to measured voltage and current, they must be set such that they will detect the faults for which they must operate while not operating unnecessarily for non-fault load conditions. Relay loadability issues were found to have played a significant role in multiple system disturbances over the years, including the August 14, 2003 blackout.[9]

The PRC-023 Reliability Standard requires applicable entities to set load-responsive phase protection relays according to specific criteria so that the relays detect and protect the grid from fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect reliability. The Commission approved the first version of this standard, PRC-023-1, in 2010. The Commission approved subsequent versions of the PRC-023 standard in 2012 (PRC-

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[9] *See* 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* (Apr. 2004), https://www.energy.gov/sites/default/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf [hereinafter *2003 Blackout Report*].

023-2), 2014 (PRC-023-3), 2015 (currently effective PRC-023-4), and most recently in 2021 (approved, but not yet effective PRC-023-5).[10]

Over time, concerns have arisen regarding the application of Requirement R2 of the PRC-023 standard, a requirement which was first introduced in PRC-023-2. This requirement relates to the setting of out-of-step blocking elements (also known as "power swing blocking"). Out-of-step blocking schemes provide increased reliability by preventing relays from tripping for stable power swings. The System Protection and Control Subcommittee identified significant confusion regarding the application of Requirement R2 that could lead to increased reliability risk by entities limiting or disabling their out-of-step blocking elements. The System Protection and Control Subcommittee further identified that the applicability exclusion in Attachment A, Item 2.3 (protection systems intended for protection during stable power swings) is no longer needed due to system changes in the intervening years; moreover, the continued existence of this unnecessary exclusion in the PRC-023 standard has contributed to the confusion regarding the application of Requirement R2. To address these concerns, NERC initiated Project 2021-05 Modifications to PRC-023 in 2021.

Proposed Reliability Standard PRC-023-6 would advance the reliability of the Bulk-Power System by retiring Requirement R2 and removing the Attachment A, Item 2.3 exclusion which is no longer needed. As discussed more fully herein, the retirement of Requirement R2 is appropriate for several interrelated reasons. First, Requirement R2 is not needed for reliability, and it is redundant to the performance required by Requirement R1. A close review of the PRC-023 development record suggests that Requirement R2 may have been developed based on an incomplete analysis of out-of-step/power swing blocking schemes and the potential technical

10 *See infra* Section III.D, History of the PRC-023 Reliability Standard.

solutions to address reliability considerations. A more complete analysis demonstrates that a separate requirement addressing out-of-step/power swing blocking is unnecessary for reliability. Further, Requirement R2 has been interpreted in such a matter that it could hinder the effective deployment of out-of-step/power swing blocking schemes when appropriate to improve BPS reliability. Retiring Requirement R2 would bring needed focus and clarity to the PRC-023 standard and would advance reliability.

In reaching its conclusion that Requirement R2 should be retired, the standard drafting team for proposed Reliability Standard PRC-023-6 considered the confusion that has arisen since its implementation, along with the associated reliability concerns. The standard drafting team also carefully considered the record of development for the PRC-023 standard, as well as compliance data, outage and misoperations data, and analysis of major system disturbances. Further, the standard drafting team considered the growing use of advanced microprocessor relays on the BPS as reducing any potential residual risk, already thought to be low, stemming from the lack of a separate Reliability Standard requirement specifically addressing out-of-step/power swing blocking schemes. On balance, the consideration of these relevant factors favors retirement.

For the reasons explained more fully in this petition, the retirement of Requirement R2 in proposed Reliability Standard PRC-023-6 is appropriate and would not result in a reliability gap. Further, the retirement of Requirement R2 would be consistent with prior Commission action on similarly unnecessary and redundant requirements under the "paragraph 81" line of proceedings.[11]

NERC respectfully requests that the Commission approve proposed Reliability Standard PRC-023-6 and the associated elements as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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[11] *See discussion* in *infra* Section III.C.

II. NOTICES AND COMMUNICATIONS

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

Lauren A. Perotti
Assistant General Counsel
North American Electric Reliability Corporation
1401 H Street, N.W.
Suite 410
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
lauren.perotti@nerc.net

Soo Jin Kim
Vice President and Director of Engineering and Standards
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile
soo.jin.kim@nerc.net

III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[12] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the BPS, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[13] of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[14] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[15] of the Commission's regulations requires the ERO to file with the Commission for its approval each new Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

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[12] 16 U.S.C. § 824o.

[13] *Id.* § 824o(b)(1).

[14] *Id.* § 824o(d)(5).

[15] 18 C.F.R. § 39.5(a).

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the BPS and to ensure that Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[16] and Section 39.5(c)[17] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process. NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[18]

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[19] and thus satisfy several of the Commission's criteria for approving Reliability Standards.[20] The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the comments of all stakeholders. Stakeholders must approve, and the NERC Board of Trustees must adopt, a new or revised Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

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16 16 U.S.C. § 824o(d)(2).

17 18 C.F.R. § 39.5(c)(1).

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

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

20 Order No. 672, *supra*, at PP 268, 270.

C. NERC Initiatives to Promote Efficiency in the Body of Reliability Standards

NERC's mission is to assure the effective and efficient reduction of risks to the reliability and security of the North American BPS. To achieve its mission, NERC maintains a body of technically sound, results-based Reliability Standards addressing various aspects of BPS planning, operations, and cyber and physical security. Throughout its history as the Commission-certified Electric Reliability Organization, NERC has periodically reassessed its Reliability Standards and has proposed modifications and retirements to improve their overall effectiveness and efficiency.

In paragraph 81 of its March 2012 order approving new NERC enforcement mechanisms, the Commission invited NERC to propose specific standards or requirements for retirement that either: (1) provide little protection for BPS reliability; or (2) are redundant with other aspects of the Reliability Standards.[21] The resulting "paragraph 81" initiative resulted in NERC proposing multiple standards retirements according to a set of defined criteria. The "paragraph 81" criteria developed by NERC to inform its proposals consisted of the following:[22]

> Criterion A (*Overarching Criterion*) The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
>
> Criteria B (*Identifying Criteria*)
>
> - B1. Administrative. The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability, and is needlessly burdensome.

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21 *See N. Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193 at P 81, *order on reh'g and clarification*, 139 FERC ¶ 61,168 (2012) ("If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief.")

22 *Petition of NERC for Approval of Retirement of Requirements in Reliability Standards*, Docket No. RM13-8-000 (Feb. 28, 2013) at Exhibit A, Paragraph 81 Criteria.

- B2. Data collection/data retention. These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

- B3. Documentation. The Reliability Standard requirement requires responsible entities to develop a document (e.g., plan, policy, or procedure) which is not necessary to protect BES reliability.

- B4. Reporting. The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity.

- B5. Periodic Updates. The Reliability Standard requirement requires responsible entities to periodically update (e.g., annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

- B6. Commercial or Business Practice. The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

- B7. Redundant. The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (e.g., Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

NERC also considered various factors under "Criteria C," consisting of whether the requirement was being considered as part of an active development project, the Violation Risk Factor for the requirement, and the tier on which the requirement falls in the Actively Monitored List.[23]

In Order No. 788, the Commission approved the proposed retirements as consistent with its March 2012 order.[24] The Commission also stated that it "voluntarily and routinely, albeit informally, reviews its regulations to ensure that they achieve their intended purpose and do not

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23 NERC subsequently added other criteria under Criteria C, including whether the Reliability Standard was part of a Find, Fix, and Track ("FFT") enforcement filing, possible negative impacts on NERC's reliability principles, possible impacts on defense in depth principles, and whether the retirement would promote results or performance based Reliability Standards. *See* Periodic Review Template at Attachment 2 (last rev. Feb. 2016), https://www.nerc.com/pa/Stand/Resources/Documents/Periodic%20Review%20Template%20Feb%202016.pdf.

24 Order No. 788, *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at P 1 (2013).

impose undue burdens on regulated entities or unnecessary costs on those entities or their customers."[25]

From 2017-2019, NERC undertook a second broad-based standards review initiative, the Standards Efficiency Review. The purpose of this review was to apply the insights gained over ten years of developing and enforcing mandatory Reliability Standards to improve the overall efficiency and effectiveness of the body of Reliability Standards. In Order No. 873, the Commission approved many of the retirements proposed by NERC under this initiative, finding that the approved retirements would "enhance the efficiency of the Reliability Standards program by reducing duplicative or otherwise unnecessary regulatory burdens." [26]

NERC continues to consider the "paragraph 81" criteria as part of its standards periodic review activities. NERC also considers the lessons learned from its standard review initiatives in developing efficient, technically sound, and results based Reliability Standards for the reliable operation of the BPS. From time to time, NERC will consider proposed retirements on an *ad hoc* basis to address specific issues identified by subject matter experts through its stakeholder committees, including issues that suggest a Reliability Standard or requirement is not achieving its intended purpose to advance reliability or is imposing undue burdens on regulated entities or unnecessary costs on those entities or their customers. As discussed below, proposed Reliability Standard PRC-023-6 was developed to address specific issues identified in the PRC-023 Reliability Standard regarding Requirement R2.

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[25] *Id.* at P 3.

[26] Order No. 873, *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards under the NERC Standards Efficiency Review*, 172 FERC ¶ 61,225 at P 3 (2020).

D. History of the PRC-023 Reliability Standard

Relay loadability refers to the ability of protective relays to restrain operation for load conditions. As protective relays can respond only to measured voltage and current, they must be set such that they will detect the faults for which they must operate while not operating unnecessarily for non-fault load conditions. Relay loadability issues were found to have played a significant role in the August 14, 2003 blackout, as well as multiple system disturbances before then, and the report from that event recommended action be taken to prevent future events.[27]

In 2008, NERC developed the initial version of the PRC-023 Reliability Standard, Reliability Standard PRC-023-1, to require applicable entities to set load-responsive phase protection relays according to specific criteria so that the relays detect and protect the grid from fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect reliability. Reliability Standard PRC-023-1 consisted of three requirements, and was applicable to Transmission Owners, Generator Owners, and Distribution Providers with load-responsive protection systems described in Attachment A to the standard on facilities meeting certain criteria. The referenced Attachment A contained three sections: first, a list of examples of load-responsive relays subject to PRC-023-1; second, a statement that "out-of-step blocking protective schemes… shall be evaluated to ensure they do not block trip for fault during the loading conditions defined within the requirements" of PRC-023-1; and third, a list of Protective Systems that are excluded from the requirements of the PRC-023-1.

In 2010, the Commission issued Order No. 733 approving Reliability Standard PRC-023-1. The Commission also directed NERC to: (1) develop certain modifications to the standard; (2) submit a timeline for the development of a new Reliability Standard to address generator protective

[27] *See, supra, 2003 Blackout Report* Recommendation 21a (p. 158).

relay loadability; and (3) develop a new Reliability Standard to address protective relay operation during stable power swings.[28] Among the Order No. 733 directives was a directive related to the original PRC-023-1 Attachment A. In the Notice of Proposed Rulemaking preceding the issuance of Order No. 733, the Commission noted that the second section of Reliability Standard PRC-023-1 Attachment A created an obligation for entities to evaluate out-of-step blocking schemes, but this obligation was not included as a requirement in the proposed standard, only in Attachment A.[29] The Commission stated that requirements should be in the requirements section of a standard to ensure compliance.[30] The Commission therefore proposed to direct NERC to modify Reliability Standard PRC-023-1 to include the second section of Attachment A regarding evaluation of out-of-step protective blocking schemes as an additional Reliability Standard requirement, with the appropriate violation risk factor and violation severity level assignments.[31] In its comments on the NOPR, NERC agreed that the proposed modification was appropriate.[32] In Order No. 733, the Commission adopted its NOPR proposal and directed NERC to make this modification to the PRC-023 standard.[33]

In 2011, NERC developed Reliability Standard PRC-023-2 to address several of the Commission's directives from Order No. 733. Reliability Standard PRC-023-2 consisted of six requirements, a revised Attachment A, and a new Attachment B regarding circuits to evaluate and

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[28] *Transmission Relay Loadability Standard*, Order No. 733, 130 FERC ¶ 61,221 at PP 60, 69, 97, 105, 108, 150, 162, 186, 203, 224, 237, 244, 264, 283, and 284 (2010) [hereinafter Order No. 733], *order on reh'g and clarification*, Order No. 733-A, 134 FERC ¶ 61,127 (2011), *order on reh'g and clarification*, Order No. 733- B, 136 FERC ¶ 61,185 (2011).

[29] Notice of Proposed Rulemaking, *Transmission Relay Loadability Reliability Standard*, 127 FERC ¶ 61,175 at P 77 (2009).

[30] *Id.*

[31] *Id.*

[32] Comments of NERC in Response to Notice of Proposed Rulemaking, Docket No. RM08-13-000 (Aug. 17, 2009) at 34.

[33] Order No. 733 at P 244.

the criteria for evaluation. Relevant to this proceeding, Reliability Standard PRC-023-2 introduced a new Requirement, Requirement R2, to address the Commission's directive to include the obligation regarding out-of-step blocking elements contained in Reliability Standard PRC-023-1 Attachment A as a Reliability Standard requirement with appropriate Violation Risk Factor and Violation Severity Level assignments.[34] The Commission approved Reliability Standard PRC-023-2 in Order No. 759.[35]

In 2013, NERC developed Reliability Standard PRC-023-3. This version of the standard contained a number of revisions intended to align and avoid overlap with the newly-developed Reliability Standard PRC-025-1 addressing generator relay loadability.[36] The Commission approved both Reliability Standards PRC-023-3 and PRC-025-1 in Order No. 799.[37]

In 2014, NERC developed the currently effective version of the PRC-023 Reliability Standard, Reliability Standard PRC-023-4. Reliability Standard PRC-023-4 was developed as part of a broader project to replace the defined term Special Protection System in Reliability Standards with the revised term Remedial Action Scheme.[38] The Commission approved the standard in Order No. 818.[39]

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34 *See* Petition of NERC for Approval of a Protection and Control (PRC) Reliability Standard, Docket No. RM11-16-000 (Mar. 18, 2011) at 12. In this filing, NERC also submitted a proposed revision to the NERC Rules of Procedure by which a registered entity could challenge a determination by a Planning Coordinator under the standard, addressing a separate Order No. 733 directive.

35 Transmission Relay Loadability Reliability Standard, Order No. 759, 138 FERC ¶ 61,197 (2012)

36 *See* Supplemental Information to the Petition of NERC for Approval of Proposed Reliability Standard PRC-025-1 (Generator Relay Loadability), Docket Nos. RM13-19-000 and RM14-3-000 (Dec. 17, 2013).

37 Generator Relay Loadability and Revised Transmission Relay Loadability Reliability Standards, Order No. 799, 148 FERC ¶ 61,042 (2014).

38 *See* Petition of NERC for Approval of Revisions to the Definition of "Remedial Action Scheme" and Proposed Reliability Standards, RM15-13-000 (Feb. 3, 2015).

39 Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards, Order No. 818, 153 FERC ¶ 61,228 (2015).

In 2021, NERC developed Reliability Standard PRC-023-5 as part of a broader project to improve the framework for establishing and communicating System Operating Limits. The changes to the standard consist of modifications in Attachment B criteria B2.[40] The Commission approved Reliability Standard PRC-023-5 in March 2022.[41] Under the approved implementation plan, Reliability Standard PRC-023-5 is scheduled to become effective in the United States on April 1, 2024.

E. Project 2021-05 Modifications to PRC-023

NERC initiated Project 2021-05 Modifications to PRC-023 in 2021 to address concerns identified by the former NERC Planning Committee System Protection and Control Subcommittee (or "SPCS")[42] regarding the application of Requirement R2 and Attachment A exclusion 2.3 in Reliability Standard PRC-023-4. The SPCS identified that Requirement R2, as it has been interpreted and applied, could lead to increased reliability risk by entities limiting or disabling their out-of-step blocking elements. The SPCS further identified that Attachment A exclusion 2.3 is no longer needed, and its continued existence has contributed to the confusion regarding the application of Requirement R2. The SPCS recommended both Requirement R2 and Attachment A exclusion 2.3 be removed from the PRC-023 standard.

The Project 2021-05 standard drafting team developed proposed Reliability Standard PRC-023-6 to address the SPCS recommendations. The proposed Reliability Standard and implementation plan were posted for formal comment period and ballot from October 10, 2022

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40 *See* Petition of NERC for Approval of Proposed Reliability Standards Related to Establishing and Communicating System Operating Limits, Docket No. RD22-2-000 (Jun. 28, 2021).

41 *N. Am. Elec. Reliability Corp.*, Docket No. RD22-2-000 (2022) (delegated letter order).

42 This group is currently known as the System Protection and Control Working Group, following the reorganization of the NERC technical committee structure under the NERC Reliability and Security Technical Committee.

through December 5, 2022.[43] The proposed Reliability Standard received 98.37% approval, with 80.66% quorum. The proposed implementation plan received 100% approval with 80.59% quorum. The proposed Reliability Standard was posted for final ballot from January 10, 2023 through January 24, 2023. The proposed Reliability Standard received 98.27% approval, with 87.96% quorum. The proposed implementation plan received 100% approval, with 87.91% quorum.

The NERC Board of Trustees adopted the proposed Reliability Standard on February 16, 2023. A summary of the development history and the complete record of development is attached to this petition as **Exhibit F**.

IV. JUSTIFICATION FOR APPROVAL

In this petition, NERC submits for Commission approval proposed Reliability Standard PRC-023-6 (Transmission Relay Loadability). The purpose of the proposed Reliability Standard, which remains unchanged from the currently effective version, is to ensure that protective relay settings shall not limit transmission loadability, not interfere with system operators' ability to take remedial action to protect system reliability, and be set to reliably detect all fault conditions and protect the electrical network from these faults.

Proposed Reliability Standard PRC-023-6 would advance the reliability of the BPS by retiring an unnecessary and redundant requirement that has contributed to confusion regarding the proper application of the PRC-023 standard to out-of-step blocking (or power swing blocking) relays. In particular, proposed Reliability Standard PRC-023-6 would retire Requirement R2. Power swing blocking relays provide increased reliability by preventing relays from tripping for stable power swings. Retiring this requirement would allow entities to apply power swing blocking

[43] The ballot was extended to reach quorum.

schemes more effectively when appropriate to improve BPS reliability. Proposed Reliability Standard PRC-023-6 also revises Attachment A to the standard to remove an exclusion that is no longer needed and which has contributed to the confusion regarding Requirement R2. The revisions and supporting rationale are discussed in further detail below. In addition to these revisions, proposed Reliability Standard PRC-023-6 reflects additional minor changes to other elements of the standard to conform to the current NERC Reliability Standard template. All changes are shown in redline in **Exhibit A-2**.

As discussed in **Exhibit D**, proposed Reliability Standard PRC-023-6 meets the Commission's criteria for approval in Order No. 672 and is just, reasonable, not unduly discriminatory, and in the public interest. Further, proposed Reliability Standard PRC-023-6 is consistent with the Commission's prior orders regarding the retirement of Reliability Standard requirements that provide little protection for Bulk-Power System reliability or are redundant.[44]

NERC respectfully requests that the Commission approve the proposed Reliability Standard to become effective in accordance with the proposed implementation plan discussed in Section V.

A. Retirement of Requirement R2

Proposed Reliability Standard PRC-023-6 would reserve (i.e., retire) Requirement R2 of currently effective Reliability Standard PRC-023-4 and approved Reliability Standard PRC-023-5. Requirement R2 provides that each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. Requirement R1 of the current and approved versions of the PRC-023

[44] *See* discussion in Section III.C, *supra*.

standard provides that each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the criteria specified in the requirement for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for *all fault conditions*.[45] The retirement of Requirement R2 is appropriate for several interrelated reasons, as discussed below and in the supporting Technical Rationale (**Exhibit C**), and is consistent with the Commission precedent regarding the retirement of Reliability Standard requirements that do not advance reliability and are redundant, as discussed above.

First, Requirement R2 is not necessary for reliability, as it does not benefit or protect the reliable operation of the BPS. In reaching this conclusion, the standard drafting team analyzed the record of development for the PRC-023 Reliability Standard in the context of the significant confusion that has arisen among protection system engineers following its enactment. The standard drafting team's analysis of the PRC-023 development record suggests that Requirement R2 may have originally been developed based on an incomplete or erroneous analysis of out-of-step blocking schemes.

As explained in Section III.C above, NERC originally developed Requirement R2 to respond to a Commission directive from Order No. 733.[46] The Commission's directive in Order No. 733 was premised on a common sense drafting principle: that NERC should ensure that obligations for entities be placed in Reliability Standard requirements with the appropriate

[45] Emphasis added. The requirement further states that each entity shall evaluate relay loadability at .85 per unit voltage and a power factor angle of 30 degrees.

[46] *See* Order No. 733 at P 244.

violation risk factors and violation severity levels to ensure compliance.[47] In response, NERC developed Requirement R2 to translate the language formerly in PRC-023-1 Attachment A establishing an obligation to evaluate out-of-step blocking schemes to a mandatory Reliability Standard requirement. The development of this requirement and the predecessor obligation in PRC-023-1 Attachment A, however, appears to have been based on an incomplete consideration of issues regarding power swings and alternative technical solutions that would assure detection and clearing of faults that may occur during power swings. Further analysis indicates that there is in fact no reliability need for such a requirement, and that it should be retired in the interest of enhancing clarity and reliability in the application of the PRC-023 standard and eliminating redundancy.

In reaching this determination, the standard drafting team analyzed the development of the first two versions of the PRC-023 standard, PRC-023-1 and PRC-023-2, where the requirement originated. This analysis included a review of the PRC-023 reference document, which provides technical information prepared to support the implementation of the PRC-023 Reliability Standard. The NERC System Protection and Control Task Force published the initial version of this reference document in August 2006.[48] This reference document was subsequently revised from

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47 *See* Notice of Proposed Rulemaking, *Transmission Relay Loadability Reliability Standard*, 127 FERC ¶ 61,175 at P 77 (2009) ("Requirements should be in the requirements section of a Reliability Standard to ensure compliance. Since the ERO intends to require the evaluation of out-of-step blocking applications, language to this effect should be included as a requirement and not as a statement in an Attachment. Consequently, the Commission proposes to direct the ERO to modify PRC-023-1 by adding the statement in section (2) of Attachment A as an additional requirement with the appropriate violation risk factor and violation severity level assignments.").

48 *Petition of NERC for Approval of PRC-023-1 Reliability Standard*, Docket No. RM08-13-000 (Jul. 30, 2008) at Exhibit D, NERC System Protection and Control Task Force of the NERC Planning Committee, *PRC-023 Reference: Determination and Application of Practical Relaying Loadability Ratings* (Aug. 14, 2006). The System Protection and Control Task Force was subsequently renamed the System Protection and Control Subcommittee of the NERC Planning Committee, and is presently known as the System Protection and Control Working Group of the NERC Reliability and Security Technical Committee.

2007-2008;[49] in the revised document, the drafters added Appendix C to discuss out-of-step blocking.[50] Notably, Appendix C described only the type of schemes that are typically implemented using electromechanical relays. The document stated, "[I]f (and as long as) a system load condition operates the out-of-step blocking relay, the tripping relay will be prevented from operating for a subsequent fault condition! A timer can be added such that the relay issues a trip if the out-of-step timer does not reset within a defined time."[51] This statement continues to appear in subsequent versions of the PRC-023 reference document, including the current version dating from 2017.[52]

Based on the standard drafting team's analysis of the PRC-023 development record, this statement in Appendix C to the PRC-023 reference document appears to have been the basis for the obligation in Reliability Standard PRC-023-1 Attachment A for entities to evaluate out-of-step blocking schemes.[53] It appears the original drafters were concerned that, with the higher loadability requirements of PRC-023, a loading condition could occur that could, via the out of step blocking protection, block phase tripping indefinitely. Hence, the cautionary statement in Reliability

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49 *See* NERC project pages for Project 2010-13.1 Phase 1 of Relay Loadability: Transmission at https://www.nerc.com/pa/Stand/Pages/Project_2010-13-1_Phase_1_of_Relay-Loadability_Transmission.aspx (history of the development of the reference document) and https://www.nerc.com/pa/Stand/Pages/Project_2010-13.1_Phase_1_of_Relay_Loadability-Transmission.aspx (history of the development of Reliability Standard PRC-023-2). The information on the latter project page is also included as Exhibit F to NERC's Petition for Approval of Reliability Standard PRC-023-2. *See Petition of NERC for Approval of a Protection and Control Reliability Standard*, Docket No. RM11-16-000 (Mar. 18, 2011).

50 NERC System Protection and Control Task Force of the NERC Planning Committee, *PRC-023 Reference: Determination and Application of Practical Relaying Loadability Ratings* (Jun. 2008), available at https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Relay_Loadability_Reference_Doc_Clean_2008July03.pdf.

51 *Id.* at 32.

52 *See* NERC System Protection and Control Subcommittee, *Determination of Practical Transmission Relaying Loadability Settings, Implementation Guidance for PRC-023-4* (Dec. 2017), available at https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/PRC-023-4%20R1%20Determination%20of%20Practical%20Transmission%20Relaying%20Loadability%20Settings%20(PC).pdf.

53 *See* discussion in Technical Rationale, Exhibit C, 3-5.

Standard PRC-023-1 Attachment A. This is the obligation that later became Requirement R2 in PRC-023-2 in response to the Commission's Order No. 733 directive, with little further discussion of the technical merits.[54] This statement in the reference document, however, is incorrect and incomplete. The first part of the statement excerpted above, "[I]f (and as long as) a system load condition operates the out-of-step blocking relay, the tripping relay will be prevented from operating for a subsequent fault condition," was, and remains, true for traditional electromechanical relay schemes. The subsequent sentence, which indicates that the timer would be used to trip the element, is not appropriate because tripping should not occur during the identified heavy load conditions unless a fault actually occurs on the element. A timer is not capable of such fault detection.[55] Further, the discussion in Appendix C to the PRC-023 reference document does not address why the "subsequent fault condition" that became the basis for Requirement R2 should be excluded from the "all fault conditions" language that remains part of Requirement R1. Given the context of Appendix C, it appears the original drafters were concerned that unmodified traditional electromechanical power swing blocking schemes may not be able to comply with loadability requirements while maintaining reliable protection of the BES for all fault conditions as required in Requirement R1. The lack of discussion of either "all fault conditions" or more advanced power swing blocking schemes, however, leaves the impression that there is no acceptable technical solution to this issue. There are, however, acceptable technical solutions.

The PRC-023-6 standard drafting team has identified several methods available to protection system engineers to remediate the fault identification issues during power swing blocking that were identified by the previous drafting team. While relay replacement is one option,

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54 *See id.* at 4-5.

55 The NERC System Protection Control Working Group is currently revising the reference document and will correct this sentence on next revision.

entities may also make modifications to traditional electromechanical power swing blocking schemes to address this issue, such as implementing more advanced interval timers or changing settings on out-of-step blinders. Some combination of these methods to power swing blocking schemes would address the technical concern to allow tripping for any fault that occurs during a heavy loading condition that results in power swing blocking operation.[56] With these enhancements to the supporting reference document, and in consideration of the broader language of Requirement R1 addressing "all fault conditions," the standard drafting team concluded that no reliability need exists for a specific requirement addressing out-of-step/power swing blocking in the PRC-023 standard.[57]

Second, the standard drafting team concluded that Requirement R2 is redundant to Requirement R1 and should be retired on that basis. This conclusion relates closely to the discussion above regarding reliability need. Specifically, the fault condition addressed by Requirement R2 is addressed by Requirement R1 and requires the same entity response.[58] Requirement R1 provides that each entity shall use one of the specified criteria to "prevent its phase protective relay settings from limiting transmission system loadability while maintaining

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[56] The standard drafting team has recommended revisions to Appendix C to the PRC-023 reference document to provide appropriate guidance to protection system engineers. *See* Exhibit F (Record of Development) at items 15 (clean) and 16 (redline). The NERC System Protection and Control Working Group of the NERC Reliability and Security Technical Committee has included consideration of these recommended revisions in its work plan for 2023.

[57] During the development process, one commenter stated that Requirement R2 "should be added to another PRC standard where the SDT may opine on its insertion subject to review by stakeholders before finalization of deletion from this Standard." In response, the standard drafting team cited its work on the Technical Rationale, stating, "Thank you for your comment. The SDT does not agree that the content of R2 needs to be included in another standard. This was reviewed at greater length in the Technical Rationale." *See* Standard Drafting Team December 2022 Consideration of Comments (Exhibit F Record of Development, item 19) at 62.

[58] Most commenters agreed with the standard drafting team that Requirement R2 was redundant to Requirement R1. However, one commenter stated that, although they still believed Requirement R2 to be unnecessary, Requirements R1 and R2 are not the same. *See* Standard Drafting Team December 2022 Consideration of Comments (Exhibit F Record of Development, item 19) at 15 (Entergy: "Agree that R2 is unnecessary but it is not the same as R1. R1 does not preclude out-of-stop [sic] blocking outside the 150% load region. R2 does. Therefore, they are not the same." Response: "Thank you for your response. We agree that R1 and R2 are not the same, but it wasn't the intent of the SDT to imply that. The SDT feels that the dependability statement in R1 covers the fault conditions of R2.").

reliable protection of the BES *for all fault conditions*" (emphasis added). Requirement R2 identifies a specific fault condition when it specifies that the applicable entity "shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1." Requirement R2 does not expand upon the "all fault conditions" identified in Requirement R1; if an entity failed to comply with Requirement R2, it would also fail to comply with Requirement R1. Requirement R1 of the PRC-023 Reliability Standard stands alone to ensure entities apply the loadability criteria while ensuring reliable fault protection, and there is no reliability benefit to maintaining a separate requirement considering what is established in Requirement R1 and other Reliability Standards.

Consistent with the Commission's October 10, 2023 request for information, NERC provides the following additional discussion in support of this conclusion below.

Some power swing blocking schemes employ an outer blinder and an inner impedance blinder with a timer that is used to determine the rate of change of apparent impedance to differentiate between a fault (fast change) and a swing (slow change). The timer starts timing when the impedance passes into (is less than) the outer blinder. If the impedance does not pass through the inner blinder (is less than), before the timer setting, the power swing blocking will declare a swing and block the load responsive elements from tripping.

As discussed above, the cautionary language that became Requirement R2 appears to have been motivated by a concern that, with the new higher loading requirements, power swing blocking could block phase tripping indefinitely. Requirement R2 essentially cautions entities to ensure that their out-of-step blocking elements allow tripping for faults that occur during the following conditions: (1) has impedance within the slow change and fast change out-of-step blocking blinders; and (2) lasts long enough for the out-of-step blocking relay to declare a power swing and block tripping.

Requirement R2 does not support directly the purpose of the PRC-023 Reliability Standard, which is “Protective relay settings shall not limit transmission loadability; not interfere with system operators’ ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.” Further, Requirement R2 does not support Requirement R1 in ensuring that trips do not occur unnecessarily due to loadability. What Requirement R2 does support, tripping for the specific conditions mentioned above, is already addressed by Requirement R1. Requirement R1 ensures that entities apply the loadability criteria “while maintaining reliable protection of the BES for all fault conditions.” Not tripping for these specific faults is failing to have a protection scheme designed to operate properly, and not having reliable protection of the BES for all fault conditions. Therefore, Requirement R2 is redundant to Requirement R1, and it is not necessary for reliability.

For certain facilities, Reliability Standard PRC-026-1 provides additional assurance. Requirement R3 of Reliability Standard PRC-026-1 – Relay Performance During Stable Power Swings[59] provides:

> **R3.** Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-1 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following:
>
> - The Protection System meets the PRC-026-1 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or

[59] In 2022, the Commission approved a subsequent version of this standard, Reliability Standard PRC-026-2. *N. Am. Elec. Reliability Corp.*, Docket No. RD22-2-000 (2022) (delegated letter order). Reliability Standard PRC-026-2 will become effective on April 1, 2024. Requirement R3 is not substantively changed from the currently effective version of the requirement.

- The Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element)

To comply with Reliability Standard PRC-026-1 Requirement R3, entities must develop a Protection System that meets the Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping. This requirement renders Reliability Standard PRC-023-5 Requirement R2–also addressing out-of-step elements–as redundant and not necessary for reliability.

Additionally, Reliability Standard PRC-027-1, which was developed after PRC-023 Requirement R2, addresses the same reliability concern as Requirement R2 in a much clearer and more comprehensive fashion. Reliability Standard PRC-027-1 – Coordination of Protection Systems for Performance During Faults requires entities to maintain coordination of Protection Systems installed to detect and isolate Faults on BES Elements, thereby ensuring that those Protection Systems operate in the intended sequence during Faults. Requirement R1 of this standard provides as follows:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include:

1.1. A review and update of short-circuit model data for the BES Elements under study.

1.2. A review of the developed Protection System settings.

1.3. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.3.1. Provide the proposed Protection System settings to the owner(s) of the electrically joined Facilities.

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.3.3. Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

1.3.4. Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

If out-of-step blocking failed to allow tripping as identified in Reliability Standard PRC-023-5 Requirement R2, an applicable event would lead to an unintended sequence of tripping, causing the primary protection scheme not to operate and resulting in secondary protection tripping of other relays through backup protection schemes. In this case, the coordination would not have been designed properly, resulting in a possible violation of Reliability Standard PRC-027-1 Requirement R1.

The October 10, 2023 request for information sought clarification on whether, if Requirement R2 were to be retired, the existing obligations in Requirement R2 would be enforced and audited under Requirement R1. As explained above, NERC has concluded that Requirement R2 is redundant to Requirement R1, and consequently, any entity noncompliance could be assessed under Requirement R1. As noted above, however, other Reliability Standards may be implicated as they address the same underlying concern.

Third, the standard drafting team considered the original identified need for this project: that industry has interpreted Requirement R2 to restrict the setting of power setting blocking elements, making determination of appropriate settings more difficult and increasing the difficulty of complying with Reliability Standard PRC-026-2 (Relay Performance During Stable Power Swings). The result is that some entities have simply chosen to disable their schemes, an undesirable and unintended consequence. Power swing blocking relays provide increased reliability by preventing relays from tripping for stable power swings. Disabling power swing blocking relays due to unclear or conflicting requirements could lead to tripping during stable power swings, an increased reliability risk. The standard drafting team identified that the confusion regarding the applicability in Requirement R2 can be traced to the change in wording as the statement regarding out-of-step blocking relays in PRC-023-1 Attachment A was converted to Requirement R2. Specifically, the wording was changed from “shall be evaluated to ensure that they do not block trip” in PRC-023-1 Attachment A to “shall set its out-of-step blocking elements to allow tripping” in PRC-023-2 Requirement R2. This change has resulted in a significant difference in how Requirement R2 is interpreted by protection system engineers. In Requirement R2, the emphasis is placed on relay settings, rather than evaluation of the power swing blocking scheme itself. Stated differently, the focus shifted from evaluating the power swing blocking scheme to the power swing blocking elements, primarily blinders, which are directly controlled by the settings. In cases of conflict, protection engineers have remedied the issue by either not using the power swing blocking scheme or significantly increasing the complexity of the scheme. The standard drafting team identified at least one entity that disabled at least two power swing blocking schemes; the first due to concerns whether use of a reset timer would achieve the spirit of Requirement R2 to clear faults within appropriate time, and a second because the outer power swing blocking characteristic could not be set within the loadability characteristics.[60] Retiring

[60] *See* Technical Rationale, Exhibit C at 5.

Requirement R2 would allow entities to apply power swing blocking schemes more effectively when appropriate to improve BPS reliability, and it would help focus the standard consistent with IEEE concepts of security and dependency as they relate to relays.[61]

Fourth, consistent with NERC's "paragraph 81" criteria framework, the standard drafting team considered other relevant factors including data from the roughly ten years of experience implementing Requirement R2. Based on this consideration, the standard drafting team concluded that its retirement is not likely to have an adverse impact on the reliability of the BPS. Indeed, as previously discussed, it is likely to advance reliability by eliminating confusion that has hindered the effective deployment of power swing blocking schemes.

In reaching its determination that retirement of Requirement R2 would not create a reliability gap, the standard drafting team considered compliance data,[62] outage and misoperations data, and analysis of major system disturbances. The standard drafting team considered that, while no statistical analysis or anecdotal data could prove that faults will never occur while a relay has asserted its power swing blocking function, the low historical occurrence of events that may qualify as faults during a power swing, perhaps as low as zero in the information reviewed by the standard drafting team, would suggest that the risk is low.[63] When considered in conjunction with the other factors described above, including an unclear reliability need, redundancy with Requirement R1, and industry confusion resulting in the disabling of power swing blocking schemes, the balance of factors favors retirement.

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[61] *See id.* at 6.

[62] The compliance data reviewed by the team indicated that the ERO Enterprise has processed only two instances of noncompliance with this requirement since it became mandatory and enforceable. Both instances were deemed to have posed a minimal risk to the reliability of the BPS and were dispositioned with no penalty through the Compliance Exception enforcement processing mechanism. *See* Violation ID RFC2013012950 (filed May 28, 2015) and MRO2013012721 (filed September 30, 2014).

[63] *See* Technical Rationale (Exhibit C) at 7-9 for a discussion of the events and data reviewed by the standard drafting team.

Last, the standard drafting team considered that protection systems deployed on the BPS continue to improve, and these improvements have and will continue to reduce any potential residual risk that the original drafters of the PRC-023 standard may have intended to be addressed by the obligation that later became Requirement R2. Since Requirement R2 became effective, many entities have continued to replace electromechanical, solid state, and early generations of microprocessor relays with newer microprocessor relays. For example, one entity that extensively applies power swing blocking and out-of-step tripping on its transmission system began 2011 with 161 of 471 (34%) of affected line terminals protected by these lower capability (electromechanical) relays. By 2022, only 19 of 699 (2.7%) of the affected line terminals were still protected by these less capable relays. A second entity upgraded all of its out of step applications to modern microprocessor-based schemes. A third entity upgraded all of its out of step applications above 200 kV to modern microprocessor relays and has only a single electromechanical application still in service at 115 kV; this application includes a power swing blocking reset timer to allow tripping for faults during power swings. The standard drafting team considered these technological advancements, along with the other factors discussed above, in concluding that no separate requirement specifically addressing out-of-step/power swing blocking is needed for reliability.

In conclusion, proposed Reliability Standard PRC-023-6 would advance the reliability of the BPS by removing an unnecessary and redundant requirement, Requirement R2, which has been the subject of much confusion and has been interpreted over time to hinder the effective deployment of power swing blocking schemes that would enhance the reliability of the BPS. Its retirement would be consistent with the Commission's precedent regarding the retirement of unnecessary and redundant requirements that do not advance reliability[64] and is in the public interest.

B. Revisions to Attachment A

In the PRC-023 Reliability Standard, Section A.4 Applicability refers to Attachment A to identify the subset of Transmission Owners, Generator Owners, and Distribution Providers to which the standard is applicable. Attachment A contains a list of protective functions included in the scope of the standard and a list of protection systems which are excluded from the requirements of the standard. In proposed Reliability Standard PRC-023-6, NERC proposes to reserve (i.e., remove) the Attachment A, Item 2.3 exclusion: Protection systems intended for protection during stable power swings.

In developing the original version of the PRC-023 Reliability Standard, the PRC-023-1 standard drafting team clarified that this exclusion, "protection systems intended for protection during stable power swings," referred to "relay systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other to maintain desirable performance relative to voltage, frequency, and power oscillations."[65] The PRC-023-1 standard drafting team cited Florida as an example of where these schemes were employed.[66]

The normal practice for power systems generally should not be to separate intentionally during stable power swings. The PRC-023-6 standard drafting team understands that the example

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64 *See* discussion in Section III.C, *supra.*

65 Project 2010-13.1 Consideration of Comments on First Draft Relay Loadability Standard (Jan. 9, 2007) at p. 48, available at https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf. This document was also included in NERC's petition for approval of Reliability Standard PRC-023-1. *See* Petition of NERC for Approval of Reliability Standard PRC-023-1, Docket No. RM08-13-000 (Jul. 30, 2008), Exhibit C (Record of Development) at item 17 (page 608 of pdf). *See also id.* at 55 (clarifying that "Where out of step tripping or blocking relays are applied independently within the system they must comply with the standard.")

66 *Id.*

scheme from Florida cited by the original PRC-023-1 standard drafting team is no longer used. Further, the continued presence of this exclusion in the PRC-023 standard when it is no longer needed has contributed to the confusion regarding Requirement R2, as it has been interpreted as being in conflict with that requirement. Attachment A, Item 2.3 should therefore be removed from the PRC-023 standard, and its removal would not create a reliability gap.

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the implementation plan attached to this petition as **Exhibit B**. The proposed implementation plan provides that proposed Reliability Standard PRC-023-6 would become effective on the later of: (1) the first day of the first calendar quarter after applicable regulatory approval; or (2) the effective date of Reliability Standard PRC-023-5.[67] The version of the PRC-023 Reliability Standard then in effect would be retired immediately prior to the effective date of Reliability Standard PRC-023-5. This implementation timeline reflects consideration of the nature of the changes proposed (i.e., retirement of a requirement), the fact that another version of the PRC-023 standard has been approved by the Commission and is pending enforceability, and NERC's general practice of implementing new standard versions on the first day of a calendar quarter for administrative efficiency.[68]

Additionally, NERC has revised the Effective Date section of the standard (Section A.5) to reference certain language in the implementation plan regarding circuits that become applicable to the standard following the annual assessment specified in Requirement R6 (Time Period to

[67] Reliability Standard PRC-023-5 is scheduled to become effective in the United States on April 1, 2024.

[68] *See* Order No. 672 at P 333 ("In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.").

Address New Designations). This inclusion is intended to aid entities in administering the standard following the effective date; the time period to address new designations has not changed from the approved implementation plan for Reliability Standard PRC-023-5.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve, as just, reasonable, not unduly discriminatory, and in the public interest:

- Proposed Reliability Standard PRC-023-6, and the associated elements, as shown in **Exhibit A**;
- the retirement of the version of the PRC-023 Reliability Standard that would then be in effect (PRC-023-4 or PRC-023-5); and
- The implementation plan included in **Exhibit B**.

Respectfully submitted,

/s/ Lauren A. Perotti

Lauren A. Perotti
Assistant General Counsel
North American Electric Reliability Corporation
1401 H Street NW, Suite 410
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

November 3, 2023

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A

Proposed Reliability Standard PRC-023-6

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-1

Proposed Reliability Standard PRC-023-6
Clean

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

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/29/2021 – 07/28/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	10/03/2022 – 11/17/2022
45-day formal or informal comment period with additional ballot	12/05/2022 – 01/18/2023
10-day final ballot	01/10/2023 – 01/19/2023
Board adoption	02/15/2023

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:** **Transmission Relay Loadability**

2. **Number:** PRC-023-6

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi- directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV

that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
    - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
    - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
    - 115% of the highest emergency rating of the series capacitor.
    - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Reserved.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

  10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

R2. Reserved.

M2. Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the

ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

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.

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record 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	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	**Reserved.**
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners,	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)	Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

D. Regional Variances

None.

E. Associated Documents

The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

NERC Reliability Standard PRC-023-6 Implementation Plan.

NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
6	March 4, 2022	FERC Order issued approving PRC-023-5	

Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

   1.1. Phase distance.

   1.2. Out-of-step tripping.

   1.3. Switch-on-to-fault.

   1.4. Overcurrent relays.

   1.5. Communications aided protection schemes including but not limited to:

   1.5.1 Permissive overreach transfer trip (POTT).

   1.5.2 Permissive under-reach transfer trip (PUTT).

   1.5.3 Directional comparison blocking (DCB).

   1.5.4 Directional comparison unblocking (DCUB).

   1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current- based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

   2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

   - Overcurrent elements that are only enabled during loss of potential conditions.
   - Elements that are only enabled during a loss of communications except as noted in section 1.6.

   2.2. Protection systems intended for the detection of ground fault conditions.

   2.3. Reserved.

   2.4. Reserved.

   2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

   2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

   2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

   2.8. Relay elements associated with dc lines.

   2.9. Relay elements associated with dc converter transformers.

Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

i. If the Facility Rating is based on a loading duration of up to and including four

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

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RELIABILITY CORPORATION

Exhibit A-2

Proposed Reliability Standard PRC-023-6
Redline

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

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/29/2021 – 07/28/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	10/03/2022 – 11/17/2022
45-day formal or informal comment period with additional ballot	12/05/2022 – 01/18/2023
10-day final ballot	01/10/2023 – 01/19/2023
Board adoption	02/15/2023

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:** **Transmission Relay Loadability**

2. **Number:** PRC-023-~~5~~6

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   4.1. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi- directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV

that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. ~~Not used~~ Reserved.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

R2. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.~~ ~~*[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*~~ Reserved.

M2. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)~~ Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-~~5~~6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~5~~6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-~~5~~6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

~~C. Measures~~

~~**M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per Standard PRC-023-5 — Transmission Relay Loadability Page 5 of 16~~

~~criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)~~

~~**M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)~~

~~**M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)~~

~~**M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)~~

~~**M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)~~

M6. ~~Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-5, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)~~

C. ~~D.~~ 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. ~~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 ~~Data~~ 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.

~~The Transmission Owner, Generator Owner, Distribution Provider and Planning 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, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and ~~Assessment Processes~~ 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.

~~• Compliance Audit~~

~~• Self-Certification~~

~~• Spot Checking~~

~~• Compliance Violation Investigation~~

~~• Self-Reporting~~

~~• Complaint~~

~~1.4. Additional Compliance Information~~

~~None.~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	Reserved. ~~**The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.**~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit. OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(part 6.2)		the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

D. ~~E.~~ Regional Variances ~~Diferences~~

None.

E. ~~F.~~ Associated ~~Supplemental Technical Reference~~ Documents

The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

NERC Reliability Standard PRC-023-6 Implementation Plan.

NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
6	March 4, 2022	FERC Order issued approving PRC-023-5	

~~PRC-023-5 —~~ Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
   - **1.1.** Phase distance.
   - **1.2.** Out-of-step tripping.
   - **1.3.** Switch-on-to-fault.
   - **1.4.** Overcurrent relays.
   - **1.5.** Communications aided protection schemes including but not limited to:
     - **1.5.1** Permissive overreach transfer trip (POTT).
     - **1.5.2** Permissive under-reach transfer trip (PUTT).
     - **1.5.3** Directional comparison blocking (DCB).
     - **1.5.4** Directional comparison unblocking (DCUB).
   - **1.6.** Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current- based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
   - **2.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
     - Overcurrent elements that are only enabled during loss of potential conditions.
     - Elements that are only enabled during a loss of communications except as noted in section 1.6.
   - **2.2.** Protection systems intended for the detection of ground fault conditions.
   - **2.3.** Reserved. ~~Protection systems intended for protection during stable power swings.~~
   - **2.4.** Reserved. ~~Not used.~~
   - **2.5.** Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
   - **2.6.** Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
   - **2.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
   - **2.8.** Relay elements associated with dc lines.
   - **2.9.** Relay elements associated with dc converter transformers.

~~PRC-023-5 —~~ Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

- **i.** If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
- **ii.** If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
- **iii.** If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Exhibit B

Implementation Plan

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Implementation Plan

Project 2021-05 Modifications to PRC-023
Reliability Standard PRC-023-6

Applicable Standard(s)

- PRC-023-6 –Transmission Relay Loadability

Requested Retirement(s)

- PRC-023-5 – Transmission Relay Loadability

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider
- Planning Coordinator

General Considerations

None.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) 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 (ii) the effective date of Reliability Standard PRC-023-5.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) 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 (ii) the effective date of Reliability Standard PRC-023-5.

Retirement Date

The version of Reliability Standard PRC-023 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-023-6.

Initial Performance Date

Each Planning Coordinator shall conduct its first assessment under Reliability Standard PRC-023-6 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-4 or PRC-023-5, whichever occurs first.

Time Period to Address New Designations

Each Transmission Owner, Generator Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

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Exhibit C

Technical Rationale

Technical Rationale for Reliability Standard PRC-023-6

January 2023

PRC-023-6 – Transmission Relay Loadability

Rationale for Applicability Section

No changes are proposed to the Applicability of Reliability Standard PRC-023-6 from the prior version.

Rationale for Retirement of Requirement R2

The most significant rationale to retire Requirement R2 is that the single fault condition regulated by Requirement R2 is a subset of the faults regulated by R1 and requires the same entity response. R2 adds nothing to the "… all fault conditions" of R1, so a failure to comply with R2 would also mean failure to comply with R1. Therefore retirement of R2 does not create a reliability gap.

The Standard Drafting Team recommends the retirement of PRC-023-5, Requirement R2.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.

The Standard Drafting Team also recommends the retirement of Attachment A, Item 2.3 exclusion:

2.3 Protection systems intended for protection during stable power swings [excluded].

Summary of Justification to Retire Requirement R2

- The fault condition regulated by Requirement R2 is also regulated by Requirement R1 and requires the same entity response.
- A significant error in the "Determination and Application of Practical Relaying Loadability Ratings," Appendix C, January 9, 2007 documentation of power swing blocking capabilities appears to have led to development of Requirement R2.
- The development history of Requirement R2 used an incomplete discussion of power swings that appears to have convinced FERC to direct a separate requirement on the subject, rather than accept alternate technical solutions that would assure detection and clearing of faults that may occur during power swings.
- The primary intent of this standard is to address a security aspect of the protection system. Adding a dependability focused requirement in this standard results in confusion in setting the protective relays.

- The roughly 10 years of experience under Requirement R2 has shown that neither compliance, system operations, nor system disturbances have had any significant impact on system reliability. In addition, whatever the original risk addressed by Requirement R2, that is now reduced due to subsequent Protection System upgrades.

I. Requirement R2 is Effectively Redundant to the Performance Required by R1 of PRC-023-5

R1 includes the phrase "… prevent its phase protective relay settings from limiting transmission system loadability *while maintaining reliable protection of the BES **for all fault conditions***." (emphasis added).

Requirement R2 singles out a specific fault condition when it specifies that the applicable entity "shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1." This is not an expansion of the "… all fault conditions" identified in R1. So if an entity failed to comply with R2, they would also fail to comply with R1.

II. Power Swing Blocking, Appendix C Error

NERC System Protection and Control Task Force (SPCTF) wrote the initial version of PRC-023 Reference Determination and Application of Practical Relaying Loadability Ratings, 8/14/2006. This document was revised on January 9, 2007 and added Appendix C to discuss out of step blocking. This discussion only referenced the type of schemes that are typically implemented using electromechanical relays. The conclusion was that "if (and as long as) a system load condition operates the out-of-step blocking relay, the distance relay will be prevented from operating for a subsequent fault condition! A timer can be added such that the relay issues a trip if the out of step timer does not reset within a defined time." Subsequent versions of this document (2017 is the latest) have not changed this wording. These two sentences appear to be the origin of the item that addressed out of step blocking in PRC-023-1 Attachment A.

The above quoted "… subsequent fault condition!" statement remains true for traditional electromechanical relay schemes. The subsequent (and last) sentence indicates that the (optional?) timer would be used to trip the element. This is not appropriate because tripping should not occur during the identified heavy load conditions unless a fault actually occurs on the element. A timer is not capable of such fault detection.

Appendix C does not discuss why the "… subsequent fault condition!" that became Requirement R2 should be excluded from "… all fault conditions" that remains part of Requirement R1. Given the context of Appendix C, the appropriate conclusion would seem to be that unmodified traditional electromechanical PSB schemes, depending on their settings, may not be able to comply with the R1 or R2 requirements. Unfortunately, the lack of discussion of either "… all fault conditions" or more advanced PSB schemes leaves the impression that there is no acceptable technical solution to this issue.

The present SDT recommends that SPCWG review and update this document and has proposed several edits and additions, including several methods available to protection engineers to remediate the fault identification issues during PSB that were identified by the original drafting team. Some combination of these methods to PSB schemes answers the technical concern to allow tripping for any fault that occurs during a heavy loading condition that results in PSB operation. In combination with the existing wording in R1, this makes the existing R2 redundant and therefore unnecessary.

Therefore the present SDT asserts that no specific reference to power swing blocking is necessary as a PRC-023 requirement, but can be appropriately acknowledged in this Technical Rationale~~,~~ and in a revision to "Determination and Application of Practical Relaying Loadability Ratings," Appendix C.

III. Development History of Requirement R2

The original August 2006 version of PRC-023 Reference Determination and Application of Practical Relaying Loadability Ratings described the standard's objective with respect to faults:

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The introduction also included item "1.3 Out-of-Step blocking," but with no further discussion.

The original wording in PRC-023-1, Attachment A regarding power swing blocking was:

This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

At least one commenter was concerned that this original wording from the PRC-023-1 SDT did not recognize that the PSB can be reset to allow detection of faults after the PSB function asserts. However, the SDT thought no change was necessary. This SDT response does not acknowledge that resetting of the PSB function is even possible.

- **Comment:** Attachment A 2. A word PERMANENTLY should be added before "block trip…"?[1]
    - **Response:** Attachment A 2- Most commenters seemed to understand the intent of this item without further clarification. If an out[-]of-step relay asserts on load and blocks the trip of fault protective relays, and a fault occurs during that loading condition, the out-of-step relay will prevent successful operation of the fault protective relay. (3/9/2007)

[1] Microsoft Word - Consider_Comments_D2_Relay_Loadability_09Mar07.doc (nerc.com), DRAFT 2 comments, pp 41-43

Another commenter expressed a related concern for remotely-connected systems. The SDT acknowledged that some scheme modification may be needed but did not describe what a "more complex" scheme would do.

- **Comment:** I am concerned that this standard as drafted would limit the application of out of step block trip functions for remotely-connected systems.[2]

    - **Response:** Attachment A, Item 2 is intended to ensure that facilities are adequately protected for faults. Out-of-step blocking elements may prevent tripping for true faults during extreme loading conditions. For conditions involving remotely-connected systems, more complex out-of-step blocking schemes may be needed. (1/31/2008)

When FERC reviewed (and eventually approved) the proposed PRC-023-1, an objection was that referencing out of step blocking in Appendix A as a "shall" item was important, but not enforceable because it was not a requirement and had no VSL or VRF. FERC observed the use of this "shall" language and directed that this item be rewritten as a requirement. FERC ordered: (Order 733, paragraph 244)

We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.

The standard drafting team for PRC-023-2 then proposed to add wording to Requirement R1:

". . . and to prevent its out-of-step blocking schemes from blocking tripping for fault conditions."

One commenter[3] at the time addressed some technical aspects of this specific wording, in part:

The specific wording proposed by the Drafting Team may prevent using the out-of-step-block functions of many modern and widely used line protection relays (e.g. SEL-321 and later models and GE-UR). These relay's OSB function first blocks the protection elements from tripping, then uses a short delay and/or other information to determine whether the observed and perhaps evolving condition really represents a fault, in which case the blocking is reset to allow tripping. Such a block/reset operation is the most common technology available and would appear to lie within the intent of FERC in [Order 733] paragraph 244, but could be excluded by the presently proposed language.

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[2] https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_Initial_Ballot_PRC-023_Relay_Loadability_31Jan08.doc DRAFT 4 Comments, p 16

[3] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=018154B3-66E2-5005-8110-C31FAFC91712 pp 169-170

Another commenter added[4]:

We suggest that the added phrase be removed from R1 and a new requirement created. Suggested wording is "Protection Systems that block for stable swings or out-of-step conditions shall be evaluated to ensure that appropriate tripping will occur for in-section faults that occur during the condition. Some additional delay may be required and is acceptable to ensure that the appropriate tripping occurs."

The SDT's conclusion was:

The SDT agrees and removed out-of-step blocking from Requirement R1. The requirement pertaining to evaluation of out-of-step blocking protection has been moved to a separate requirement (now Requirement R2) to more clearly delineate this requirement from assessment of relay loadability of phase protective relays.

Both of these commenters suggested what became R2 but did not question whether "… all fault conditions" in R1 already included the faults intended to be detected by R2. It appears that, although NERC is permitted to propose an equally efficient and effective alternative to address a FERC directive, the SDT did not consider any alternate solution to FERC's Order 733 directive to include a separate requirement to detect PSB-related faults.

The SDT's proposed (and eventually approved) Violation Severity Level (VSL) and Violation Risk Factor (VRF) for both PRC-023-2 Requirements R1 and R2 were the same.

This SDT realizes that the meaning of original language in the Attachment A was inverted as it was converted to Requirement R2. The wording was changed from "…shall be evaluated to ensure that they do not block trip …" to "… shall set its out-of-step blocking elements to allow tripping …". This resulted in a significant change in how the Requirement R2 is interpreted by protection engineers. The revised emphasis is on relay settings, rather than evaluation of the PSB scheme itself. The focus shifted from evaluating the PSB scheme to the PSB elements, primarily blinders, which are directly controlled by the settings. In cases of conflict, the remedy was to either not use the PSB scheme or significantly increase the scheme complexity.

At least one entity disabled at least two power swing blocking schemes

- Due to concern whether use of a reset timer would achieve the spirit of Requirement R2 to clear faults within appropriate time.
- The outer PSB characteristic could not be set within the loadability characteristics.

[4] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=018154B3-66E2-5005-8110-C31FAFC91712 p 189

IV. Security versus Dependability[5]

The Purpose of PRC-023 is:

Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

The emphasis of PRC-023 is on the security of the transmission system to avoid unnecessary trips during heavy load conditions when no fault occurs. The Purpose and Requirement R1 does include language that "… all fault conditions" (dependability) must be recognized. Requirement R2 carves out a separate dependability item "… to allow tripping of phase protective relays for faults that occur during the loading conditions" as in R1.

The dependability language in R1 is an appropriate balancing of the intent of R1 (security), so mentioning dependability in R1 does not cause confusion. Retiring R2 will make the standard more focused and clear.

V. Experience with Requirement R2 functionality

Experience is not a perfect guide to judging the necessity of Requirement R2. Absence of evidence is not evidence of absence of failure to clear faults during PSB operations. The approximately 10 years of available history since R2 has been enforceable does provide useful background to judge the scale of potential risk to the bulk power system following R2 retirement. No statistical analysis or antidotal examples can prove that faults will never occur while a relay has asserted its PSB function. However, the extremely small historical occurrence of events that may qualify as faults during a power swing, perhaps as low as zero in this summary, does significantly limit the risk to the bulk power system.

Compliance Violations

A review of compliance violations of the existing Requirement R2 showed only two violations, both discovered about one year after the requirement became enforceable. Both were discovered through review of documentation of relay settings, not from system operations. In both cases the associated Risk Description indicated that the issues posed minimal risk to the reliability of the bulk power system.

An audit finding was due to a 12% deviation from the required loadability and only affected one of the two redundant protection systems. The entity re-calculated their relay settings and found no other related issues on their system.

[5] For the purpose of this discussion the IEEE Standard Dictionary of Electrical and Electronics Terms defines dependability (relay or relay systems) as the facet of reliability that relates to the degree of certainty that a relay or relay system will operate correctly. Similarly, security (relay or relay systems) is the facet of reliability that relates to the degree of certainty that a relay or relay system will not operate incorrectly. Finally, reliability (relay or relay systems) is a measure of the degree of certainty that a relay or relay system will perform correctly. NOTE: Reliability denotes certainty of correct operation together with assurance against incorrect operation from all extraneous causes.

A self-report identified that one of three redundant protection schemes on each of three transmission lines was impacted by an OSB calculation error. Relay settings on the other two protection schemes for each transmission line were not impacted and acceptable fault clearing would have occurred even if the loading conditions specified in PRC-023-2 R1 were to occur simultaneously with a three-phase fault on the line.

It does not appear that any risk was imposed to the Bulk Power System from these violations, or even whether failure of one of two or three redundant relays to trip for a fault would have constituted a Misoperation since the Composite Protection System would have operated correctly.

Outage and Misoperation Experience

The SDT reviewed TADS and MIDAS data for misoperations involving three phase faults which are more likely to result in power swings and are the events regulated by Requirement R2. For the approximately 5 years of reliable MIDAS data covering about 40,000 total operations, only 11 possible events were discovered, and only a single event involved relays. From the available event descriptions it is not clear that Requirement R2 prevented any of these events.

Major System Disturbances

The NERC Event Analysis web site includes reports for 18 major events. The SDT was also able to review the FRCC disturbance of February 26, 2008 (not listed on the NERC site). These reports were reviewed to discover whether any system impacts were identified from faults during relay power swing block operations. The time range of these events starts before R2 was enforceable until summer 2021. The short summary is that Requirement R2 does not seem to have improved or detracted from system performance during any of these major system disturbances.

Several event reports describe the issues that have been noted regarding PV (lack of) ride through capability during voltage sags associated with fault clearing. There are significant overlapping causes associated with these events. However, these reports describe nothing related to power swings or PSB.

- **June-August 2021 CAISO Solar PV Disturbance Report**
- **May/June 2021 Odessa Disturbance Report**
- **July 2020 San Fernando Solar PV Reduction Disturbance Report**
- **April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report**
- **October 2017 Canyon 2 Fire Disturbance Report**
- **August 2016 1200 MW Fault Induced Solar Photovoltaic Resources Interruption Disturbance Report**

Several event reports cover system performance during cold weather events, hurricanes, and other major weather conditions. Most system impacts resulted from physical damage. None of these reports identified any system impacts due to faults during power swings or power swing blocking. Protection System impacts from all of these events ranged from very minor to none.

- **Cold Weather Training Materials**
    - This is guidance material for preparation and response rather than an event description.
- **January 2014 Polar Vortex Review**
- **October 2012 Hurricane Sandy Event Analysis Report**
- **October 2011 Northeast Snowstorm Event**
    - One relay misoperation was identified, though the specific cause was not described. However, many transmission outages did not destabilize the BPS or regional systems.
- **January 2018 South Central Cold Weather Event Report**
    - Large scale impacts to generation capability, but no specific faults involved, no PSB involved, no recommendation regarding protection against transmission power swings
- **September 2017 Hurricane Irma Event Analysis Report**
    - More than 100 storm forced transmission outages and 3300 MW forced plant outages. There were no identified misoperations that contributed to BPS facilities being out of service during the storm.
- **August 2017 Hurricane Harvey Event Analysis Report**
    - About 225 transmission assets impacted, maximum 21+ GW generation unavailable (ERCOT + MISO). No noted protection system misoperations, power swings, or PSB.

Several events had more traditional and direct electrical causes, but none indicated any power system impact due to faults during power swing blocking conditions.

January 2019 Eastern Interconnection Forced Oscillation Event Report

- PT failure at a Florida plant induced oscillations throughout the Eastern Interconnection: 200 MW swings at the plant, 50 MW in new England. No faults involved, no PSB involved, no recommendation regarding protection against transmission power swings.

- **April 2015 Washington D.C. Area Low-Voltage Disturbance Event**
    - 58 second fault clearing resulting from equipment failure and protection system misoperations of two auxiliary tripping systems. Recommendations relate to trip auxiliary

design and breaker failure initiate. No noted impacts from power swings or PSB.

- **September 2011 Southwest Blackout Event**

    - FERC/NERC Staff Report on the September 8, 2011 Blackout affecting Arizona and Southern California identified that large open circuit angles were not monitored for particular facilities in Arizona to determine whether closing could be safely accomplished. However, this result affected restoration rather than resulting from any power swing on the system, so did not involve PSB. The San Onofre nuclear plant also tripped on turbine control logic as local frequency spiked above 61 Hz. No fault or tripping was associated with a power swing or PSB.

- **FRCC System Disturbance**
    - The FRCC disturbance of February 26, 2008 included a zone 1 trip during a power swing (PSB was not applied) but was roughly the 15th event in the disturbance sequence. The report did not recommend any related protection system changes.

- **August 2003 Northeast Blackout Event**

    - The Northeast blackout of August 14, 2003 did involve a few out of step line trips on distance relay elements late in the event sequence that may have been prevented by application of PSB. However, the entire event did not include any case of failure to clear a fault due to PSB relay elements failing to reset under relay loadability conditions described in PRC-023.

Protection System Improvements

Most entities have continued to replace electromechanical, solid state, and early generations of microprocessor relays with newer microprocessor relays since Requirement R2 became effective. The effect of these upgrades is that these newer relays can more easily comply with the intent of the original wording in Appendix A of PRC-023-1. This upgrade process further reduces any risk that is intended to be addressed by Requirement R2. For example, one entity that extensively applies PSB and out of step tripping on its transmission system began 2011 with 161 of 471 (34%) of affected line terminals protected by these lower capability (electromechanical) relays. By 2022 only 19 of 699 (2.7%) of the affected line terminals were still protected by these less capable relays. A second entity has upgraded all of their out of step applications to modern microprocessor-based schemes. A third entity has upgraded all of its out of step applications above 200 kV to modern microprocessor relays and has only a single electromechanical application still in service at 115 kV.

Justification to Retire Attachment A, Item 2.3 Exclusion

Attachment A item 2.3 excludes "Protection systems intended for protection during stable power swings". This exclusion is referencing "Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations"[6]. Florida was cited in the record of development as an example of where these schemes were employed. Research has indicated that these schemes no longer exist and there is no need for a power swing tripping exclusion. PRC-026 covers stable power swings adequately. Since Item 2.3 is an exclusion, there is no overlap with PRC-026.

The original PRC-023-1 SDT response to comments included the following statements:

- (12) In some parts of North America (for example Florida), there are relay systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other to maintain desirable performance …. [footnote 6, p 48]
- Where out of step tripping or blocking relays are applied independently within the system they must comply with the standard. [footnote 6, p 55]

The normal practice for power systems generally should not be to intentionally separate during stable power swings. It is the understanding of the present Standard Drafting Team that the example scheme from Florida is no longer used. The second bullet response seems to say that exclusion 2.3 should never have been included.

The present Standard Drafting Team asserts that Attachment A, Item 2.3 can be safely retired without creating a reliability gap.

[6] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

Exhibit D

Order No. 672 Criteria

Exhibit D — Order No. 672 Criteria — Proposed Reliability Standard PRC-023-6

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

The purpose of proposed Reliability Standard PRC-023-6, which remains unchanged from currently effective version PRC-023-4 and approved version PRC-023-5, is to ensure that protective relay settings shall not limit transmission loadability, not interfere with system operators' ability to take remedial action to protect system reliability, and be set to reliably detect all fault conditions and protect the electrical network from these faults.

2. **Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]**

The proposed Reliability Standard is applicable only to users, owners, and operators of the Bulk-Power System and is clear and unambiguous as to what is required and who is to comply, in accordance with Order No. 672. The proposed Reliability Standard applies to Transmission Owners, Generator Owners, and Distribution Providers with certain systems described in the standard, and Planning Coordinators. The proposed Reliability Standard clearly articulates the

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

[2] Order No. 672 at P 321, 324.

[3] *Id.* at P 322, 325.

actions that such entities must take to comply with the standard, each of which are triggered by articulated actions and situations.

3. **A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]**

The Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment, as discussed further in **Exhibit E**, and are unchanged from currently effective version PRC-023-4 and approved version PRC-023-5. The assignment of the severity level of each VSL is consistent with the corresponding requirement and will ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

4. **A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]**

The proposed Reliability Standard contains measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements would be enforced and help ensure that the requirements would be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]**

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[4] *Id.* at P 326.
[5] *Id.* at P 327.
[6] *Id.* at P 328.

The proposed Reliability Standard achieves its reliability goal effectively and efficiently in accordance with Order No. 672. The proposed revisions reflected in proposed Reliability Standard PRC-023-6 would achieve its reliability goal by retiring redundant and unnecessary language that has contributed to confusion regarding the proper application of the PRC-023 standard to out-of-step blocking[7] relays. Out-of-step blocking schemes provide increased reliability by preventing relays from tripping for stable power swings. Proper setting of relays continues to be addressed in Requirement R1.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[8]**

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, proposed PRC-023-6 would enhance reliability by retiring redundant and unnecessary language in the standard. The NERC System Protection and Control Subcommittee identified significant confusion regarding the application of Requirement R2 that could lead to increased reliability risk by entities limiting or disabling their out-of-step blocking elements. The System Protection and Control Subcommittee further identified that the applicability exclusion in Attachment A, Item 2.3 (protection systems intended for protection during stable power swings) is no longer needed due to system changes in the intervening years; moreover, the continued existence of this unnecessary exclusion in the PRC-023 standard has contributed to the confusion regarding the application of Requirement R2.

Following a comprehensive analysis of the relevant development history for the PRC-023 standard, as well as consideration of other factors consistent with NERC's "paragraph 81" criteria,

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[7] The term "power swing blocking" is also used to describe these elements. Except where quoted, the terms are used interchangeably in this filing.

[8] Order No. 672 at PP 329-330.

the PRC-023-6 standard drafting team concluded that Requirement R2 and Attachment A, Item 2.3 should be retired, and their retirements would not create a reliability gap in the PRC-023 standard. The rationale for these changes is further detailed in the petition and the Technical Rationale, attached as **Exhibit C**.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**[9]

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.**[10]

The proposed Reliability Standard would have no undue negative effect on competition and would not unreasonably restrict the available transmission capacity or limit the use of the BPS in a preferential manner. The proposed standard would require the same performance by each of the applicable entities.

9. **The implementation time for the proposed Reliability Standard is reasonable.**[11]

The proposed effective date for the PRC-023-6 is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. NERC proposes an effective date for the proposed Reliability Standard on the later of: (1) the first day of the first calendar quarter after applicable regulatory approval; or

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[9] *Id.* at P 331.
[10] *Id.* at P 332.
[11] *Id.* at P 333.

(2) the effective date of Reliability Standard PRC-023-5.[12] This implementation timeline reflects consideration of the nature of the changes proposed (i.e. retirement of a requirement), the fact that another version of the PRC-023 standard has been approved by the Commission and is pending enforceability, and NERC's general practice of implementing new standard versions on the first day of a calendar quarter for administrative efficiency. The proposed effective date is explained in the proposed Implementation Plan, attached as **Exhibit B**.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[13]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards.[14] **Exhibit F** includes a summary of the proposed standard development proceedings and details the processes followed to develop the proposed Reliability Standard. These processes included, among other things, comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[15]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard PRC-023-6. No comments were received indicating the proposed Reliability Standard is in conflict with other vital public interests.

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[12] Reliability Standard PRC-023-5 is scheduled to become effective in the United States on April 1, 2024.

[13] Order No. 672 at P 334.

[14] *See* NERC Rules of Procedure, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual).

[15] Order No. 672 at P 335.

12. Proposed Reliability Standards must consider any other appropriate factors.[16]

No other factors relevant to whether the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential were identified.

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16 *Id.* at P 323.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit E

Analysis of Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-05 Modifications to PRC-023-4

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

PRC-023-6

VRF Justification for PRC-023-6, Requirement R1

The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R1

The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R2

The VRF has been removed since this Requirement is retired from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R2

The VSL has been removed since this Requirement is retired from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R3

The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R3

The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R4

The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R4

The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R5

The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R5

The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R6
The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R6
The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

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Exhibit F

Summary of Development and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standard PRC-023-6 – Transmission Relay Loadability.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team ("SDT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2021-05 Modifications to PRC-023 SDT members is included in **Exhibit G**.

II. Standard Development History

A. Standard Authorization Request Development

In response to some industry confusion regarding Requirement R2 and Attachment A exclusion 2.3, the NERC System Protection and Control Subcommittee[3] developed a Standard Authorization Request ("SAR") which proposed to remove those elements from the standard. The SAR was endorsed by the NERC Reliability and Security Technical Committee in October 2020.[4]

At its January 20, 2021 meeting, the NERC Standards Committee ("SC") accepted the SAR, approved posting for 30-day informal comment period, and authorized the solicitation of

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2022).

2 The NERC Standard Processes Manual is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

3 The System Protection and Control Task Force was subsequently renamed the System Protection and Control Subcommittee of the NERC Planning Committee, and is presently known as the System Protection and Control Working Group of the NERC Reliability and Security Technical Committee.

4 NERC Reliability and Security Technical Committee, *Oct. 14, 2020 Meeting Minutes* at Agenda Item 5, https://www.nerc.com/comm/RSTC/AgendaHighlightsandMinutes/1_2%20RSTC_Minutes_Oct_14_2020_v2_Final.pdf.

drafting team members.[5] The SAR was posted from June 29, 2021 through July 28, 2021. Drafting Team nominations were posted from June 29, 2021 through August 10, 2021 (extended to solicit additional nominations).

At its December 15, 2021 meeting, the SC accepted the revised SAR from the Project 2021-05 SAR Drafting Team.[6] The SC also authorized drafting revisions to PRC-023 and appointed the Project 2021-05 SAR Drafting Team as the Project 2021-05 Standard Drafting Team ("SDT").[7]

B. First Posting – Comment Period, Initial Ballot, and Non-binding Poll

On September 21, 2022, the SC authorized initial posting of proposed Reliability Standard PRC-023-6, the associated Implementation Plan, and other associated documents for a 45-day formal comment period and initial ballot.[8] The formal comment period took place from October 10, 2022 through December 5, 2022, with a parallel initial ballot and non-binding poll for the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VRSs") held from November 23, 2022 through December 5, 2022.[9]

The initial ballot and non-binding poll results for the proposed Reliability Standard are as follows:

- Proposed Reliability Standard PRC-023-6 received 98.37% approval, reaching quorum at 80.66% of the ballot pool.[10]

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5 NERC Standards Committee, *Jan. 20, 2021 Conference Call Minutes* at Agenda Item 10, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_January_Minutes_Approved_February_17_2021.pdf.

6 NERC Standards Committee, *Dec. 15, 2021 Conference Call Minutes* at Agenda Item 6, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20December%20Meeting%20%20Minutes%20-%20Approved%20January%2019,%202022.pdf.

7 *Id.*

8 NERC Standards Committee, *Sept. 21, 2022 Conference Call Minutes* at Agenda Item 12, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20September%20Minutes%20-%20Approved%20October%2019,%202022.pdf.

9 The formal comment period and initial ballot and was extended to reach quorum.

10 Exhibit F, *Complete Record of Development* at item 22.

- The Implementation Plan received 100% approval, reaching quorum at 80.59% of the ballot pool.[11]
- The non-binding poll for the associated VRFs and VSLs received 99.36% supportive opinions, reaching quorum at 78.46% of the ballot pool.[12]

C. Final Ballot

Proposed Reliability Standard PRC-023-6 and the associated Implementation Plan were posted for final ballot from January 10, 2023 through January 24, 2023. The ballot results were as follows:

- Proposed Reliability Standard PRC-023-6 received 98.27% approval, reaching quorum at 87.96% of the ballot pool.[13]
- The Implementation Plan received 100% approval, reaching quorum at 87.91% of the ballot pool.[14]

D. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standard PRC-023-6, the Implementation Plan, VRFs and VSLs, and approved the retirement of PRC-023-5 on February 16, 2023.[15]

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[11] *Id.* at item 23.
[12] *Id.* at item 24.
[13] *Id.* at item 35.
[14] *Id.* at item 36.
[15] NERC, *Board of Trustees Agenda Package* (Feb. 16, 2023) Agenda Item 8b (Project 2021-05 Modifications to PRC-023), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_Agenda_Package_February_16_2023.pdf.

Complete Record of Development

Project 2021-05 Modifications to PRC-023

Related Files

Status

The final ballot for **PRC-023-6 - Transmission Relay Loadability,** as well as the implementation plan, concluded **8 p.m. Eastern, Tuesday, January 24, 2023.**

Background

Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking[1] (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their PSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. PSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed or modified because it has been interpreted to restrict the setting of PSB elements making determination of appropriate settings more difficult and making compliance with PRC-026 more difficult. The present inclusion of out of step tripping in Attachment A, Item 1.2 needs to be clarified.

Attachment A exclusion 2.3 should also be removed or modified. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are either not needed or should be modified in the Standard.

Standard(s) Affected: PRC-023-4

Purpose/Industry Need

The purpose of the proposed project provides a reliability-related benefit by modifying or eliminating PRC-023-4 Requirement R2 to more effectively apply PSB when appropriate to improve BES reliability. Proper application of PSB can also be helpful in complying with PRC-026. It will modify or remove an exclusion (Attachment A – 2.3) that may no longer be needed.

[1] The term power swing blocking (PSB) is also used by industry to describe these elements. The PSB term will be used for the remainder of this SAR.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **PRC-023-6** Clean **(25)** | Redline to Last Posted **(26)** | Redline to Last Approved **(27)** **PRC-023-5** Clean **(28)** **Implementation Plan** Clean **(29)** | Redline to Last Posted **(30)** **Supporting Materials** **Technical Rationale** Clean **(31)** | Redline to Last Posted **(32)**	**Final Ballot** Updated Info **(33)** Info **(34)** Vote	01/10/23 - 01/24/23	Ballot Results PRC-023-6 **(35)** Implementation Plan **(36)**	
Draft 1 **PRC-023-6** Clean **(9)** Corrected file posted 1/12/2023 to reflect the proposed changes to the currently approved standard language | Redline **(10)** Implementation Plan **(11)** **Supporting Materials** Unofficial Comment Form **(12)** VRF/VSL Justifications **(13)** Technical Rationale **(14)** **Appendix C** Clean **(15)** | Redline **(16)**	Initial Ballots and Non-binding Poll Updated Info **(20)** Info **(21)** Vote	11/23/22 - 12/05/22 (Extended to reach quorum)	Ballot Results PRC-023-6 **(22)** Implementation Plan **(23)** Non-binding Poll Results **(24)**	
	Join Ballot Pools	10/10/22 - 11/15/22		
	Comment Period Info **(17)** Submit Comments	10/10/22 - 12/05/22 (Extended to reach quorum)	Comments Received **(18)**	Consideration of Comments **(19)**
Standard Authorization Request (SAR) Clean **(7)** | Redline **(8)**	The Standards Committee accepted the SAR on December 15, 2021			

Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(5)**	Nomination Period Info **(6)** (Updated) Submit Nominations	06/29/21 - 08/10/21 (Extended)		
Standard Authorization Request (1) **Supporting Materials** Unofficial Comment Form (Word) **(2)**	Comment Period Info **(3)** Submit Comments	06/29/21 - 07/28/21	Comments Received **(4)**	

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

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

<table>
<tr><th colspan="4">Requested information</th></tr>
<tr><td>SAR Title:</td><td colspan="3">Revisions to PRC-023-4</td></tr>
<tr><td>Date Submitted:</td><td colspan="3">October 19, 2020</td></tr>
<tr><td colspan="4">SAR Requester</td></tr>
<tr><td>Name:</td><td colspan="3">Jeff Iler, Chair & Bill Crossland, Vice Chair (on behalf of)</td></tr>
<tr><td>Organization:</td><td colspan="3">NERC System Protection and Control Subcommittee</td></tr>
<tr><td>Telephone:</td><td>Jeff: (614) 933-2373
Bill: (216) 503-0600</td><td>Email:</td><td>Jeff: jwiler@aep.com
Bill: bill.crossland@rfirst.org</td></tr>
<tr><td colspan="4">SAR Type (Check as many as apply)</td></tr>
<tr><td colspan="2">☐ New Standard
☒ Revision to Existing Standard
☐ Add, Modify or Retire a Glossary Term
☐ Withdraw/retire an Existing Standard</td><td colspan="2">☐ Imminent Action/ Confidential Issue (SPM Section 10)
☐ Variance development or revision
☐ Other (Please specify)</td></tr>
<tr><td colspan="4">Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)</td></tr>
<tr><td colspan="2">☐ Regulatory Initiation
☐ Emerging Risk (Reliability Issues Steering Committee) Identified
☐ Reliability Standard Development Plan</td><td colspan="2">☒ NERC Standing Committee Identified
☐ Enhanced Periodic Review Initiated
☐ Industry Stakeholder Identified</td></tr>
<tr><td colspan="4">Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):</td></tr>
<tr><td colspan="4">Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking[1] (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. OOSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed because it has been interpreted to restrict the setting of OOSB elements making compliance with PRC-026 more difficult.
Attachment A exclusion 2.3 should also be removed. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been</td></tr>
</table>

[1] The term power swing blocking (PSB) is also used by industry to describe these elements

Requested information
interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are not needed in the Standard.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of the proposed project provides a reliability-related benefit by eliminating PRC-023-4 Requirement R2. This will eliminate entities disabling their OOSB elements unnecessarily. It will remove an unnecessary exclusion (Attachment A – 2.3) for relays that no longer need an exclusion.
Project Scope (Define the parameters of the proposed project):
The scope includes: • Retire Requirement R2. • Remove Attachment A, Item 2.3 exclusion with regard to the use of protection systems during stable power swings. • Make comporting changes to the standard as needed to address the retirement of Requirement R2 and to remove Attachment A, Item 2.3 exclusion. • Ensure that removing the Item 2.3 exclusion does not overlap or create a gap with intent of PRC-026 – Relay Performance During Stable Power Swings. • Making any administrative non-substantive corrections. • Modify the Supplemental Technical Reference Document, “Determination and Application of Practical Relaying Loadability Ratings Version 1”, referenced in PRC-023-4, as needed to address the retirements and removal. Specifically, the Out of Step Blocking section.
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):
The PRC-023 standard is about setting protective relays so they do not limit transmission loadability, meaning they do not trip unnecessarily during heavy loading conditions while still being capable of detecting all fault conditions.[3] The intent of Requirement R2 is to ensure out-of-step blocking (OOSB) elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability. Requirement R2 is about ensuring OOSB elements allow blocked relay elements to trip reliably (i.e., if a three-phase fault occurs while OOSB is asserted) and not about ensuring protection systems do not limit transmission loadability. OOSB elements differentiate between power swings and three-phase faults. During a power swing, a OOSB element will typically block phase distance elements (i.e., Zone 1 & Zone 2 phase distance elements) from tripping. According to Requirement R2, a OOSB element must unblock the blocked phase distance elements for faults that occur

[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] PRC-023-4, Purpose: “Protective relay settings shall not limit transmission loadability; not interfere with system operators’ ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.”

Requested information
during the loading conditions used to set the protective relay under Requirement R1. Also in the standard, Attachment A, Item 2.3 excludes protection systems intended for protection during stable power swings and is seen as contradictory with Requirement R2 because these protection systems are associated with the use of OOSB elements, whose primary purpose is to ensure phase distance elements don't trip during stable power swings. The apparent intent of Requirement R2 is to ensure that OOSB elements don't pick up, time out, and block distance elements from tripping for three-phase faults during the loading conditions described in Requirement R1. The protection engineer must ensure reliable fault protection and has various tools in modern microprocessor based relays to ensure the dependable unblocking of tripping elements during faults. Applying the loadability criteria while ensuring reliable fault protection is already an underpinning of Requirement R1.[4] For example, an engineer can apply the use of override timers[5] that are available in modern microprocessor relays or can add such timers to existing electromechanical relay elements. An engineer can also use advanced microprocessor-based zero-setting OOSB algorithms. Applying the loadability criteria to relay settings under Requirement R1 somewhat meets the intent of Requirement R2 because Requirement R1 mandates not limiting transmission loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Additionally, Requirement R2 restrictively dictates the boundary setting of the OOSB element that starts the OOSB timer which has the overall effect of reducing the slip rate for which the OOSB element will correctly block. This results in decreasing the security of the protection scheme and increasing the chance that a misoperation of a distance element will occur for power swings that are faster than the allowable slip rate. Requirement R2 also impacts the ability to comply with NERC Reliability Standard PRC-026 (Relay Performance During Stable Power Swings) in that it affects the application of OOSB relaying that is integral to the purpose of PRC-026, which is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions". Attachment A, 2.3 was included for protection systems that intentionally trip during power swing disturbances, such as intentional islanding schemes. Florida was cited as an example of where these schemes were employed. Research has indicated that these schemes no longer exist and there is no need for a power swing tripping exclusion. Requirement R2 was added to PRC-023 in version 2 after filing version 1 with FERC.[6] FERC observed that Attachment A item 2 in PRC-023-1 was a requirement and that it needed to be included in the requirements section of a standard with the appropriate violation risk factors and violation severity levels.

[4] PRC-023-4, "R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability **while maintaining reliable protection of the BES for all fault conditions**. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees."
[5] OOSB relays with override timers will allow the OOSB blinder that starts the timer to be set beyond the loadability region prescribed by the standard. The OOSB relay would unblock after a predetermined delay should an unlikely three-phase fault occur.
[6] See FERC Order 733 para 244 https://www.ferc.gov/whats-new/comm-meet/2010/031810/E-5.pdf

Requested information
The original SDT included the "warning" in Attachment A item 2, with regards to OOSB, in reference to the OOSB timer. Some OOSB schemes employ an outer and an inner impedance blinder with a timer that is used to determine the rate of change of apparent impedance to differentiate between a fault (fast change) and a swing (slow change). The timer starts timing when the impedance passes through (is less than) the outer blinder. If the impedance does not pass through the inner blinder (is less than), before the timer setting, the OOSB will declare a swing and block the phase distance elements from tripping. The SDT wanted to inform entities that they could experience loading conditions that would result in an impedance that was between the OOSB blinders for a long period of time that would result in the blocking of the phase tripping elements indefinitely. This condition could exist at any time regardless of a relay loadability requirement. Therefore, this should not be a requirement associated with PRC-023. It is good engineering practice to ensure your relays will operate properly for all conditions they are expected to experience. This should not be a requirement in a relay loadability Standard. OOSB elements are included in the Relay Performance During Stable Power Swings Standard PRC-026-1. PRC-026-1 already includes the language "while maintaining dependable fault detection" in regards to OOSB supervision. Attachment A item 2.3 excludes "Protection systems intended for protection during stable power swings". This exclusion is referencing "Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations"[7]. These Out of Step Tripping (OOST) protection systems are better addressed in the standard for power swings, PRC-026.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Should reduce cost to Registered Entities by eliminating the compliance monitoring of a requirement that is addressed by another standard. Revising the exemption should not have a significant impact on cost.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Transmission facilities that use OOSB functionality and that experience significant oscillations (i.e., power swings) has the benefit of ensuring the system remains intact where separation of portions of the transmission system could occur due to power swings.
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 Owner, Generator Owner, and Distribution Provider

[7] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

Requested information
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.
N/A
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)?
PRC-026 – Relay Performance During Stable Power Swings (Note: Project 2015-09 – Establish and Communicate System Operating Limits is proposing modifications to PRC-026 due to revisions to the definition of System Operating Limit).
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.
N/A

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

[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.

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
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

Unofficial Comment Form

Project 2021-05 Modifications to PRC-023

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-05 Modifications to PRC-023 Standard Authorization Request (SAR).** Comments must be submitted by **8 p.m. Eastern, Wednesday, July 28, 2021.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 404-446-9618.

Background Information

Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking[1] (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. OOSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed because it has been interpreted to restrict the setting of OOSB elements making compliance with PRC-026 more difficult.

Attachment A exclusion 2.3 should also be removed. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are not needed in the Standard.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. Provide any additional comments for the SAR drafting team to consider, if desired.

   Comments:

[1] The term power swing blocking (PSB) is also used by industry to describe these elements

Standards Announcement

Project 2021-05 Modifications to PRC-023 Standard Authorization Request

Comment Period Open through July 28, 2021

Now Available

A 30-day informal comment period for the **Project 2021-05 Modifications to PRC-023 Standard Authorization Request**, is open through **8 p.m. Eastern, Wednesday, July 28, 2021**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 404-446-9618. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2021-05 Modifications to PRC-023" in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2021-05 Modifications to PRC-023 | Standard Authorization Request
Comment Period Start Date:	6/29/2021
Comment Period End Date:	7/28/2021
Associated Ballots:	

There were 32 sets of responses, including comments from approximately 102 different people from approximately 86 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

2. Provide any additional comments for the SAR drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Susan Sosbe	Wabash Valley Power Association	3	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	4	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Jodi Jensen	Western Area Power Administration - Upper Great Plains East (WAPA)	1,6	MRO

					John Chang	Manitoba Hydro	1,3,6	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1,3,5	MRO
					Joe DePoorter	Madison Gas and Electric	4	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					Bill Shultz	Southern Company Generation	5	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee no NGrid	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC

Alan Adamson	New York State Reliability Council	7	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Helen Lainis	IESO	2	NPCC
David Kiguel	Independent	7	NPCC
Nick Kowalczyk	Orange and Rockland	1	NPCC
Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
Nurul Abser	NB Power Corporation	1	NPCC

					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Jim Grant	NYISO	2	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	1,3,5,6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma	3	MRO

						Gas and Electric Co.		
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
R2 was included in PRC-023-4 for the express reason that, should a FAULT on the protected element occur during heavy load flows anticipated by the standard, OOSB elements will not detect the transition from a load condition to a FAULT as a swing and block tripping for that condition. Absent this requirement, there is a definite possibility that OOSB elements would restrain tripping for these FAULT conditions, and thereby result in a un-cleared fault. Similarly, Attachment A, 2.3 endeavors to assure that FAULTS during stable power swings will be detected and cleared.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	No
Document Name	
Comment	
MPC supports MRO NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The NSRF offers the following perspective for consideration by the Standard Drafting Team (SDT) as the issue under consideration appears to be one of Dependability (tripping when needed) and Security (preventing overtripping when not needed) and determining what requirements are needed to provide the most reliable result.

As stated in the "Background" section on the Project 2021-05 page, the requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. If that is the case, is the answer to eliminate the dependability requirement in favor of security or is there a way to clarify the standard to balance and achieve both objectives at the same time? If not, the SAR should be updated for clarity.

Dependability: The provisions in PRC-023 that require tripping for three-phase faults during stable power swings should remain. To the extent a short-circuit fault occurs on a transmission line at the time of a stable power swing, protection systems must be capable of detecting the fault, distinguishing it from the stable power swing and tripping the line accordingly.

For lines identified as meeting one or more of the four criteria outlined in PRC-026-1 R1, ensuring fault protection during stable power swings could be accomplished by installing either two redundant line differential schemes (where line differential schemes respond to all short-circuit faults but not to high loading or power swings) or a primary line differential scheme and a backup phase distance relay scheme (such as a DCB scheme).

Security: At the same time, the protection system should also be designed to avoid tripping on stable power swings in accordance with NERC PRC 026-1.

Out-of-step blocking could be employed to block tripping of the backup phase distance relay scheme for a stable power swing, but the line differential scheme would not be subject to supervision by the out-of-step blocking scheme as line differential relays do not respond to loading or power swings, and thus the line differential relay could ensure tripping for three-phase faults even when a stable power swing exists just prior to the fault.

Given the relatively few number of lines where stable power swings are typically an issue (i.e., meet one or more of the four criteria in PRC-026-1 Requirement 1), the above approach would provide superior protection to a scheme that disables fault protection during a stable power swing, thus exposing a power system to a potential catastrophic event. Given the possibility of multiple faults occurring close in time due to a common root cause (e.g., area weather patterns that tend to cause multiple transmission short-circuit faults such as lightning or wind), it is important to maintain short-circuit fault protection at all times, and this can be done in a manner that also avoids false tripping due to stable power swings.

For this reason, we do not see the need to modify PRC-023-1 to remove the requirement that fault protection is in place during stable power swings.

Likes 0	
Dislikes 0	

Response

Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF

Answer	No
Document Name	

Comment

- ITC agrees with the proposed scope of removing R2 but for a different reason than the SAR's rationale. Modern relays which ITC is familiar with incorporate standard logic in OOSB functions to ensure tripping for 3ph faults during a power swing or loading inside the first blinder. Furthermore, it is a matter of good engineering practice to ensure tripping during conditions such as a swing or heavy line loading. This requirement is therefore simply an administrative burden without improving reliability. PRC-026 already ensures that if OOSB is needed that reliable fault detection is maintained.

- ITC disagrees with the proposed scope removal of Att A 2.3. With the removal of R2, the confusion with Att A 2.3 is addressed and we should not anticipate what OOST for stable power swings may exist in the future that need to be covered by this exclusion.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment

MISO offers the following perspective for consideration by the Standard Drafting Team (SDT) as the issue under consideration appears to be one of Dependability (tripping when needed) and Security (preventing overtripping when not needed) and determining what requirements are needed to provide the most reliable result.

As stated in the "Background" section on the Project 2021-05 page, the requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. If that is the case, it appears the answer should be to **clarify** the requirement as opposed to retiring it, to retain the Dependability aspect of the requirement. Alternatively, there may be a justification to retire the requirement; however, it is not clearly stated in the SAR. If the latter is the case, the SDT should clarify that in the SAR.

Recommendation: Modify "Industry Need" section as indicated below or revise the statement to justify why retiring the Dependability requirement will not result in less reliable operation:

"Requirement R2 should be clarified or removed because it has been interpreted to restrict the setting of OOSB elements making compliance with PRC-026 more difficult.

MISO suggests there *may* be a way for Dependability and Security objectives to be achieved at the same time (below).

Dependability: The provisions in PRC-023 that require tripping for three-phase faults during stable power swings should remain. To the extent a short-circuit fault occurs on a transmission line at the time of a stable power swing, protection systems must be capable of detecting the fault, distinguishing it from the stable power swing and tripping the line accordingly.

For lines identified as meeting one or more of the four criteria outlined in PRC-026-1 R1, ensuring fault protection during stable power swings could be accomplished by installing either two redundant line differential schemes (where line differential schemes respond to all short-circuit faults but not to high loading or power swings) or a primary line differential scheme and a backup phase distance relay scheme (such as a DCB scheme).

Security: At the same time, the protection system should also be designed to avoid tripping on stable power swings in accordance with NERC PRC 026-1.

Out-of-step blocking could be employed to block tripping of the backup phase distance relay scheme for a stable power swing, but the line differential scheme would not be subject to supervision by the out-of-step blocking scheme as line differential relays do not respond to loading or power swings, and thus the line differential relay could ensure tripping for three-phase faults even when a stable power swing exists just prior to the fault.

Given the relatively few number of lines where stable power swings are typically an issue (i.e., meet one or more of the four criteria in PRC-026-1 Requirement 1), the above approach would provide superior protection to a scheme that disables fault protection during a stable power swing, thus exposing a power system to a potential catastrophic event. Given the possibility of multiple faults occurring close in time due to a common root cause (e.g., area weather patterns that tend to cause multiple transmission short-circuit faults such as lightning or wind), it is important to maintain short-circuit fault protection at all times, and this can be done in a manner that also avoids false tripping due to stable power swings.

For this reason, we do not see the need to modify PRC-023-1 to remove the requirement that fault protection is in place during stable power swings.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

N/A.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	Yes
Document Name	

Comment

Not applicable for HQP

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	

While not related to the SAR's concerns, the standard should define the period a TO, GO, or DP has to bring a circuit in compliance with R1 following notification by the PC of the circuit's inclusion on a list of circuits per application of Attachment B within standard itself. This period was previously defined in the Implementation Plan PRC-023-3, and was carried forward to PRC-023-4 by a FERC order (in Docket RD18-6-000) approving a second-filed errata to the RAS Implementation Plan. It seems inappropriate for a time period requiring ongoing use to be included in an Implementation Plan rather than the body of the standard. Any SDT assigned to revise PRC-023-4 should also address this issue, but if not, the SDT needs to define the period in the new Implementation Plan.

Likes 0	
Dislikes 0	
Response	

Jeremy Lorigan - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	

While we do not necessarily agree completely with the arguments and justifications put forth in the SAR, :

- If industry confusion due to R2 and exclusion A2.3 has indeed led to utilities disabling the OOSB elements(for which no substantiating data have been provided in the SAR) without first making sure that disabling OOSB cannot lead to system instability that could cause cascading phenomena and eventual system collapse, then,
- we do agree with the objective of the SAR that removal of such confusion is a good thing and would recommend that the decision to enable or disable OOSB should occur on a case-by-case basis after the required studies are performed.

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	

Comment	
The requirement R2 and the attachment A 2.3 cause interpretation confusion and the proposal to remove both from the requirements would allow the normal functioning of the OOSB relays during power swing conditions.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
MEC supports MRO NSRF comments. MEC notes there are two opposing concerns, a potential conflict between PRC-026 and PRC-023 versus possible tripping. MEC believes the SAR should move forward even if there is a scope question and would like the SDT to investigate NERC standard conflict concerns between PRC-026 and PRC-023. It's MEC's understanding that if a transmission line is identified for PRC-026, a way to comply with PRC-026 is to enable Out-Of-Step blocking, but PRC-023 R2 interferes with that solution by too restrictively burdening the settings for the outer blinder technology to be dependable, therefore causing more compliance issues for the Transmission Owner to solve, hence why entities are removing the schemes.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed SAR.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee no NGrid	
Answer	Yes
Document Name	
Comment	
The NPCC RSC agrees with the proposed scope as described in the SAR.	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Exelon supports the proposed SAR.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 1,3,5,6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE agrees Requirement R2 should be evaluated for the reasons given in the SAR. Texas RE recommends the drafting team consider an exception process to allow for out-of-step relays to trip for unstable power swings that may fall within the criteria in Requirement R1.	
Likes 0	
Dislikes 0	
Response	

2. Provide any additional comments for the SAR drafting team to consider, if desired.

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

Expand the scope of the SAR to align "trip" and "operate" terminology in PRC-023 with PRC-026.

If modifications to PRC-023 move forward, the SDT should consider addressing another problematic aspect of the standard; i.e. the use of the term "operate" in lieu of "trip" in the various criteria associated with Requirement 1. Aligning the wording in PRC-023 with PRC-026 would help to ensure clarity and consistency of application.

The term "operate" typically applies to the operation of a single relay element whereas the term "trip" typically applies to the tripping of one or more circuit breakers, and thus the isolation of a protective zone. Having said this, an entire transmission relay scheme is often comprised of multiple relay elements, and thus more than one element must "operate" to initiate a "trip". Therefore, if the goal is to avoid a false trip, all that is necessary is to ensure at least one of the relay elements will not operate. It is not necessary to ensure all relay elements associated with the protective relay scheme will not operate.

For example, in a direction comparison blocking scheme, the Zone 3 mho distance element (21) is often supervised by a non-directional overcurrent unit (50), and both elements must operate to initiate a trip. The non-directional overcurrent relay element must reach for faults on the opposite end of the line and possibly beyond to facilitate remote backup protection, and this requirement often means the overcurrent relay element must be set such that it could operate under high levels of loading (particularly for longer lines), but this will not result in a line trip since the Zone 3 mho distance element will not operate, thus the scheme should be compliant with the spirit of PRC-023, which is to avoid false tripping under high loading conditions. However, one could interpret the term "operate" as applied to individual relay elements in Requirement 1 based on the way the standard is drafted, and this interpretation would require that none of the relay elements are allowed to operate under load, which is an unnecessary requirement that makes compliance much more challenging.

While to date the interpretation of the standard is to avoid tripping and this should be the intent of the standard, the actual application is not well aligned with that interpretation.

Expand the make-up of the SDT to include a representative from an end-user perspective

MISO agrees with the SAR that the core of the SDT should consist of individuals from the TO, GO and DP functions. That said, we also recommend the SDT consider including an individual(s) from an end-use perspective; i.e. one TOP and/or one TP on the SDT.

Likes 0	
Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	

Document Name	
Comment	
- PRC-026 already ensures that if OOSB is needed that reliable fault detection is maintained.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment. ACES appreciates the efforts of drafting team members and NERC staff in continuing to enhance the standards for the benefit of reliability of the BES.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

- **Expand the scope of the SAR to align "trip" and "operate" terminology in PRC-023 with PRC-026**.

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Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	
Document Name	
Comment	
MPC supports MRO NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	
Document Name	
Comment	

MEC supports MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	
Document Name	

Comment

Following additional points should be considered.

- R1 criteria 6 should be removed as it is not used. This has just been used as a place holder after subsequent revisions in PRC-023-3 and PRC-023-4'
- Attachment A 2.4 should be removed as it is not used. This has just been used as a place holder after subsequent revisions in PRC-023-3 and PRC-023-4.

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA is presently facing a situation where we need to add an OOSB function to two transmission lines, but PRC-023 R2 prevents us from doing so with the existing relays. We can see the need to take a closer look at PRC-023 R2 to possibly eliminate the issues that this requirement creates.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
No additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Additional response received from Charles Yeung – Southwest Power Pool, Inc. (RTO) – on behalf of ISO RTO Council SRC Members

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

   ☒ Yes
   ☐ No

   Comments:

2. Provide any additional comments for the SAR drafting team to consider, if desired.

   Comments:

Unofficial Nomination Form

Project 2021-05 Modifications to PRC-023

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2021-05 Modifications to PRC-023** drafting team members by **8 p.m. Eastern, Wednesday, July 28, 2021.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 404-446-9618.

Background Information

Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking[1] (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. OOSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed because it has been interpreted to restrict the setting of OOSB elements making compliance with PRC-026 more difficult.

Attachment A exclusion 2.3 should also be removed. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are not needed in the Standard.

Standard affected: PRC-023-4

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below. By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

The time commitment for this project is expected to be one meeting per quarter (on average two and a half full working days each meeting) with calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome. NERC is seeking individuals who have subject matter expertise with Protection & Controls and are familiar with NERC Standard PRC-023.

[1] The term power swing blocking (PSB) is also used by industry to describe these elements

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):
Acknowledgement that the nominee has read and understands both the *NERC Participant Conduct Policy* and the *Standard Drafting Team Scope* documents, available on NERC Standards Resources. ☐ Yes, the nominee has read and understands these documents.

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ MRO ☐ NPCC ☐ RF	☐ SERC ☐ Texas RE ☐ WECC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[2] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[2] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

UPDATED
Standards Announcement
Project 2021-05 Modifications to PRC-023

Nomination Period Extended, Now Open through August 10, 2021

Now Available

Additional nominations are being sought for Project 2021-05 Modifications to PRC-023 drafting team members through **8 p.m. Eastern, Tuesday, August 10, 2021**.

Use the electronic form to submit a nomination. Contact Wendy Muller regarding issues with the system. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below. By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

The time commitment for this project is expected to be one meeting per quarter (on average two and a half full working days each meeting) with calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome. NERC is seeking individuals who have subject matter expertise with Protection & Controls and are familiar with NERC Standard PRC-023.

Next Steps

The Standards Committee is expected to appoint members to the drafting team in September 2021. Nominees will be notified shortly after they have been appointed.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 404-446-9618. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-05 Modifications to PRC-023” in the Description Box.

404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

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:	Revisions to PRC-023-4		
Date Submitted:	October 19, 2020 (Revised on November 16, 2021)		
SAR Requester			
Name:	Jeff Iler, Chair & Bill Crossland, Vice Chair (on behalf of) (Revised by Project 2021-05 SAR Drafting Team)		
Organization:	NERC System Protection and Control Working Group		
Telephone:	Jeff: (614) 933-2373 Bill: (216) 503-0600	Email:	Jeff: jwiler@aep.com Bill: bill.crossland@rfirst.org
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?):			
Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking[1] (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their PSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. PSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed or modified because it has been interpreted to restrict the setting of PSB elements making determination of appropriate settings more difficult and making compliance with PRC-026 more difficult. The present inclusion of out of step tripping in Attachment A, Item 1.2 needs to be clarified.			

[1] The term power swing blocking (PSB) is also used by industry to describe these elements. The PSB term will be used for the remainder of this SAR.

Requested information
Attachment A exclusion 2.3 should also be removed or modified. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are either not needed or should be modified in the Standard.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of the proposed project provides a reliability-related benefit by modifying or eliminating PRC-023-4 Requirement R2 to more effectively apply PSB when appropriate to improve BES reliability. Proper application of PSB can also be helpful in complying with PRC-026. It will modify or remove an exclusion (Attachment A – 2.3) that may no longer be needed.
Project Scope (Define the parameters of the proposed project):
The scope includes: • Retire or modify Requirement R2. • Remove or modify Attachment A, Item 2.3 exclusion. • Make changes to the standard as needed to address modifications to Requirement R2 and Attachment A, Item 2.3 exclusion. • Ensure that removing or modifying the Item 2.3 exclusion does not overlap or create a gap with the intent of PRC-026 – Relay Performance During Stable Power Swings. • Clarify how much time an entity has between the Requirement R6 identification and implementation of relay settings. • Clarify the inclusion of out of step tripping in Attachment A, Item 1.2. • Make any administrative, non-substantive modifications suggested in industry comments. • Modify the Supplemental Technical Reference Document, “Determination and Application of Practical Relaying Loadability Ratings Version 1”, referenced in PRC-023-4, as needed to address these modifications, specifically, the Out of Step Blocking [Power Swing Blocking] section.
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):
The PRC-023 standard is about setting protective relays so they do not limit transmission loadability, meaning they do not trip unnecessarily during heavy loading conditions while still being capable of detecting all fault conditions.[3] The intent of Requirement R2 is to ensure power swing blocking (PSB) elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability. Requirement R2 is about ensuring PSB elements allow blocked

[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] PRC-023-4, Purpose: “Protective relay settings shall not limit transmission loadability; not interfere with system operators’ ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.”

Requested information
relay elements to trip reliably (i.e., if a three-phase fault occurs while PSB is asserted) and not about ensuring protection systems do not limit transmission loadability. PSB elements differentiate between power swings and three-phase faults. During a power swing, a PSB element will typically block appropriate load responsive protective elements from operating. According to Requirement R2, a PSB element must unblock the blocked elements for faults that occur during the loading conditions used to set the protective relay under Requirement R1. Also in the standard, Attachment A, Item 2.3 excludes protection systems intended for protection during stable power swings and may contradict Requirement R2 because these protection systems are associated with the use of PSB elements, whose primary purpose is to ensure load responsive protective elements don’t operate during stable power swings. The apparent intent of Requirement R2 is to ensure that PSB elements don’t pick up, time out, and block load responsive protective elements from operating for three-phase faults during the loading conditions described in Requirement R1. The protection engineer must ensure reliable fault protection and has various tools in modern microprocessor based relays to ensure the dependable unblocking of tripping elements during faults. Applying the loadability criteria while ensuring reliable fault protection is already an underpinning of Requirement R1.[4] For example, an engineer can apply the use of reset timers[5] that are available in modern microprocessor relays or can add such timers to existing electromechanical relay schemes. An engineer can also use continuous measurement-based PSB algorithms. Applying the loadability criteria to relay settings under Requirement R1 somewhat meets the intent of Requirement R2 because Requirement R1 mandates not limiting transmission loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Additionally, Requirement R2 restrictively dictates the boundary setting of the PSB element that starts the PSB timer which has the overall effect of reducing the slip rate for which the PSB element will correctly block. This can result in decreasing the security of the protection scheme and increasing the chance that a misoperation of a distance element will occur for power swings that are faster than the allowable slip rate. Requirement R2 also may impact the ability to comply with NERC Reliability Standard PRC-026 (Relay Performance During Stable Power Swings) to the extent that it affects the application of PSB relaying that is integral to the purpose of PRC-026, which is “[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions”. Requirement R2 was added to PRC-023 in version 2 after filing version 1 with FERC.[6] FERC observed that Attachment A item 2 in PRC-023-1 was a requirement and that it needed to be included in the requirements section of a standard with the appropriate violation risk factors and violation severity levels. The original SDT included the “warning” in Attachment A item 2, with regards to PSB, in reference to the PSB timer. Some PSB schemes employ an outer and an inner impedance blinder with a timer that is used

[4] PRC-023-4, “R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability **while maintaining reliable protection of the BES for all fault conditions**. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.”

[5] PSB relays with reset timers will allow the PSB blinder that starts the timer to be set beyond the loadability region prescribed by the standard. The PSB relay would unblock after a predetermined delay should an unlikely three-phase fault occur.

[6] See FERC Order 733 para 244 https://www.ferc.gov/whats-new/comm-meet/2010/031810/E-5.pdf

Requested information
to determine the rate of change of apparent impedance to differentiate between a fault (fast change) and a swing (slow change). The timer starts timing when the impedance passes into (is less than) the outer blinder. If the impedance does not pass through the inner blinder (is less than), before the timer setting, the PSB will declare a swing and block the load responsive elements from tripping. The SDT wanted to inform entities that they could experience loading conditions that would result in an impedance that was between the PSB blinders for a long period of time that would result in the blocking of the load responsive elements indefinitely. It is good engineering practice to ensure relays will operate properly for all conditions they are expected to experience. It is questionable how a relay tripping requirement should be in a relay loadability Standard. PSB elements are included in the Relay Performance During Stable Power Swings Standard PRC-026-1, but additional coordination with PRC-023 may be appropriate. PRC-026-1 already includes the language “while maintaining dependable fault detection” in regard to PSB supervision. Attachment A, 2.3 was included for protection systems that intentionally trip during stable power swing disturbances, such as intentional islanding schemes. This exclusion is referencing “Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations”[7]. Florida was cited as an example of where these schemes were employed. Research has indicated that these schemes no longer exist so there is no need for a stable power swing tripping exclusion.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The goal is to ensure BES reliability. The SDT can’t specifically identify the cost result until the final language is developed, but expects that there should be no significant impact on costs.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Transmission facilities that use PSB functionality and that experience significant oscillations (i.e., power swings) have the benefit of ensuring the system remains intact where unintended separation of portions of the transmission system could occur due to power swings.
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):
Planning Coordinator, Transmission Owner, Generator Owner, and Distribution Provider

[7] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

Requested information
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.
N/A
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)?
PRC-026 – Relay Performance During Stable Power Swings (Note: Project 2015-09 – Establish and Communicate System Operating Limits has proposed modifications to PRC-026 due to revisions to the definition of System Operating Limit). This project is pending approval in FERC Docket RM21-19. Depending on the changes made to PRC-023, there could be a need to align the changes with PRC-026.
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.
N/A

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

[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.

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
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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

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:	Revisions to PRC-023-4		
Date Submitted:	October 19, 2020 (Revised on November 16, 2021)		
SAR Requester			
Name:	Jeff Iler, Chair & Bill Crossland, Vice Chair (on behalf of) (Revised by Project 2021-05 SAR Drafting Team)		
Organization:	NERC System Protection and Control ~~Subcommittee~~Working Group		
Telephone:	Jeff: (614) 933-2373 Bill: (216) 503-0600	Email:	Jeff: jwiler@aep.com Bill: bill.crossland@rfirst.org
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?):			
Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking[1] (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their ~~OOSB~~ PSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. PSB~~OOSB~~ relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed or modified because it has been interpreted to restrict the setting of PSB~~OOSB~~ elements making determination of appropriate settings more difficult and making compliance with PRC-026 more difficult. The present inclusion of out of step tripping in Attachment A, Item 1.2 needs to be clarified.			

[1] The term power swing blocking (PSB) is also used by industry to describe these elements. The PSB term will be used for the remainder of this SAR.

Requested information
Attachment A exclusion 2.3 should also be removed or modified. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are either not needed or should be modified in the Standard.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of the proposed project provides a reliability-related benefit by modifying or eliminating PRC-023-4 Requirement R2 to ~~. This will eliminate entities disabling their OOSB elements unnecessarily~~more effectively apply PSB when appropriate to improve BES reliability. Proper application of PSB can also be helpful in complying with PRC-026. It will modify or remove an ~~unnecessary~~ exclusion (Attachment A – 2.3) ~~for relays that~~ that may no longer be needed~~ an exclusion~~.
Project Scope (Define the parameters of the proposed project):
The scope includes: • Retire or modify Requirement R2. • Remove or modify Attachment A, Item 2.3 exclusion~~ with regard to the use of protection systems during stable power swings~~. • Make~~ comporting~~ changes to the standard as needed to address modifications to Requirement R2 and Attachment A, Item 2.3 exclusion.~~the retirement of Requirement R2 and to remove Attachment A, Item 2.3 exclusion.~~ • Ensure that removing or modifying the Item 2.3 exclusion does not overlap or create a gap with the intent of PRC-026 – Relay Performance During Stable Power Swings. • Clarify how much time an entity has between the Requirement R6 identification and implementation of relay settings. • Clarify the inclusion of out of step tripping in Attachment A, Item 1.2. • Makeing any administrative, non-substantive modifications~~corrections.~~ suggested in industry comments. • Modify the Supplemental Technical Reference Document, “Determination and Application of Practical Relaying Loadability Ratings Version 1”, referenced in PRC-023-4, as needed to address these modifications,~~ retirements and removal.~~ specifically, the Out of Step Blocking [Power Swing Blocking] section.
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):
The PRC-023 standard is about setting protective relays so they do not limit transmission loadability, meaning they do not trip unnecessarily during heavy loading conditions while still being capable of

[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.

Requested information
detecting all fault conditions.[3] The intent of Requirement R2 is to ensure ~~out-of-step~~power swing blocking ~~(OOSB)~~ (PSB) elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability. Requirement R2 is about ensuring PSB~~OOSB~~ elements allow blocked relay elements to trip reliably (i.e., if a three-phase fault occurs while PSB~~OOSB~~ is asserted) and not about ensuring protection systems do not limit transmission loadability. PSB~~OOSB~~ elements differentiate between power swings and three-phase faults. During a power swing, a PSB~~OOSB~~ element will typically block appropriate load responsive protective elements ~~phase distance elements (i.e., Zone 1 & Zone 2 phase distance elements)~~ from operating~~tripping~~. According to Requirement R2, a PSB~~OOSB~~ element must unblock the blocked ~~phase distance~~ elements for faults that occur during the loading conditions used to set the protective relay under Requirement R1. Also in the standard, Attachment A, Item 2.3 excludes protection systems intended for protection during stable power swings and ~~is seen as~~may contradict~~ory with~~ Requirement R2 because these protection systems are associated with the use of PSB~~OOSB~~ elements, whose primary purpose is to ensure load responsive protective ~~phase distance~~ elements don't operate~~trip~~ during stable power swings. The apparent intent of Requirement R2 is to ensure that PSB~~OOSB~~ elements don't pick up, time out, and block load responsive protective~~distance~~ elements from ~~tripp~~operating for three-phase faults during the loading conditions described in Requirement R1. The protection engineer must ensure reliable fault protection and has various tools in modern microprocessor based relays to ensure the dependable unblocking of tripping elements during faults. Applying the loadability criteria while ensuring reliable fault protection is already an underpinning of Requirement R1.[4] For example, an engineer can apply the use of ~~override~~ reset timers[5] that are available in modern microprocessor relays or can add such timers to existing electromechanical relay schemes~~ elements~~. An engineer can also use ~~advanced microprocessor-based~~ continuous measurement-based PSB ~~zero-setting OOSB~~ algorithms. Applying the loadability criteria to relay settings under Requirement R1 somewhat meets the intent of Requirement R2 because Requirement R1 mandates not limiting transmission loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Additionally, Requirement R2 restrictively dictates the boundary setting of the PSB~~OOSB~~ element that starts the PSB~~OOSB~~ timer which has the overall effect of reducing the slip rate for which the PSB~~OOSB~~ element will correctly block. This can result~~s~~ in decreasing the security of the protection scheme and increasing the chance that a misoperation of a distance element will occur for power swings that are faster than the allowable slip rate. Requirement R2 also may impact~~s~~ the ability to comply with NERC Reliability Standard PRC-026 (Relay Performance During Stable Power Swings) to the extent that~~in that~~ it affects the application of PSB~~OOSB~~ relaying that is integral to

[3] PRC-023-4, Purpose: "Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults."

[4] PRC-023-4, "R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability **while maintaining reliable protection of the BES for all fault conditions**. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees."

[5] ~~OOSB~~ PSB relays with reset~~override~~ timers will allow the PSB~~OOSB~~ blinder that starts the timer to be set beyond the loadability region prescribed by the standard. The PSB~~OOSB~~ relay would unblock after a predetermined delay should an unlikely three-phase fault occur.

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the purpose of PRC-026, which is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions". ~~Attachment A, 2.3 was included for protection systems that intentionally trip during power swing disturbances, such as intentional islanding schemes. Florida was cited as an example of where these schemes were employed. Research has indicated that these schemes no longer exist and there is no need for a power swing tripping exclusion.~~ Requirement R2 was added to PRC-023 in version 2 after filing version 1 with FERC.[6] FERC observed that Attachment A item 2 in PRC-023-1 was a requirement and that it needed to be included in the requirements section of a standard with the appropriate violation risk factors and violation severity levels. The original SDT included the "warning" in Attachment A item 2, with regards to PSB~~OOSB~~, in reference to the PSB~~OOSB~~ timer. Some PSB~~OOSB~~ schemes employ an outer and an inner impedance blinder with a timer that is used to determine the rate of change of apparent impedance to differentiate between a fault (fast change) and a swing (slow change). The timer starts timing when the impedance passes ~~through~~ into (is less than) the outer blinder. If the impedance does not pass through the inner blinder (is less than), before the timer setting, the PSB~~OOSB~~ will declare a swing and block the ~~phase distance~~load responsive elements from tripping. The SDT wanted to inform entities that they could experience loading conditions that would result in an impedance that was between the PSB~~OOSB~~ blinders for a long period of time that would result in the blocking of the load responsive~~phase tripping~~ elements indefinitely. ~~This condition could exist at any time regardless of a relay loadability requirement. Therefore, this should not be a requirement associated with PRC-023.~~ It is good engineering practice to ensure ~~your~~ relays will operate properly for all conditions they are expected to experience. It is questionable how a relay tripping~~This should not be a~~ requirement~~-~~ should be in a relay loadability Standard. PSB~~OOSB~~ elements are included in the Relay Performance During Stable Power Swings Standard PRC-026-1, but additional coordination with PRC-023 may be appropriate. PRC-026-1 already includes the language "while maintaining dependable fault detection" in regard~~s~~ to PSB~~OOSB~~ supervision. Attachment A, 2.3 was included for protection systems that intentionally trip during stable power swing disturbances, such as intentional islanding schemes. This exclusion is referencing "Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations"[7]. Florida was cited as an example of where these schemes were employed. Research has indicated that these schemes no longer exist so there is no need for a stable power swing tripping exclusion. ~~Attachment A item 2.3 excludes "Protection systems intended for protection during stable power swings". This exclusion is referencing "Protection systems installed specifically to separate portions of the system~~

[6] See FERC Order 733 para 244 https://www.ferc.gov/whats-new/comm-meet/2010/031810/E-5.pdf
[7] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

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~~that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations"[8]. These Out of Step Tripping (OOST) protection systems are better addressed in the standard for power swings, PRC-026.~~
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
~~Should reduce cost to Registered Entities by eliminating the compliance monitoring of a requirement that is addressed by another standard. Revising the exemption should not have a significant impact on cost.~~The goal is to ensure BES reliability. The SDT can't specifically identify the cost result until the final language is developed, but expects that there should be no significant impact on costs.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Transmission facilities that use ~~OOSB~~ PSB functionality and that experience significant oscillations (i.e., power swings) have~~s~~ the benefit of ensuring the system remains intact where unintended separation of portions of the transmission system could occur due to power swings.
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):
Planning Coordinator, Transmission Owner, Generator Owner, and Distribution Provider
Do you know of any consensus building activities[9] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
N/A
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)?
PRC-026 – Relay Performance During Stable Power Swings (Note: Project 2015-09 – Establish and Communicate System Operating Limits has~~is~~ proposed~~ing~~ modifications to PRC-026 due to revisions to the definition of System Operating Limit). This project is pending approval in FERC Docket RM21-19. Depending on the changes made to PRC-023, there could be a need to align the changes with PRC-026.
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.
N/A

~~[8] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf~~

[9] 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.

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
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

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

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/29/2021 – 07/28/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	10/03/2022 – 11/17/2022
45-day formal or informal comment period with additional ballot	12/05/2022 – 01/18/2023
10-day final ballot	02/13/2023 – 02/22/2023
Board adoption	03/22/2023

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:** **Transmission Relay Loadability**
2. **Number:** PRC-023-6
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi- directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV

that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
    - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
    - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
    - 115% of the highest emergency rating of the series capacitor.
    - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
7. Set transmission line relays applied on the load-end of transmission lines that serve

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

8. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

  10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

9. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutesto provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no lessthan 140° C for the winding hot spot temperature[3].

10. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

11. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

R2. Reserved.

M2. Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

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 Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning 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, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

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

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	**Reserved.**
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners,	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)	Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

A. Regional Variances

None.

B. Associated Documents

The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

NERC Reliability Standard PRC-023-6 Implementation Plan.

NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
5	DATE	Add FERC approval history	
6		Revised by Project….	Retired Requirement R2, remove Attachment A, Section/Part 2.3

Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

    1.1. Phase distance.

    1.2. Out-of-step tripping.

    1.3. Switch-on-to-fault.

    1.4. Overcurrent relays.

    1.5. Communications aided protection schemes including but not limited to:

    1.5.1 Permissive overreach transfer trip (POTT).

    1.5.2 Permissive under-reach transfer trip (PUTT).

    1.5.3 Directional comparison blocking (DCB).

    1.5.4 Directional comparison unblocking (DCUB).

    1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current- based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

    2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.

    2.2. Protection systems intended for the detection of ground fault conditions.

    2.3. Reserved.

    2.4. Reserved

    2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

    2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

    2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

    2.8. Relay elements associated with dc lines.

    2.9. Relay elements associated with dc converter transformers.

Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

i. If the Facility Rating is based on a loading duration of up to and including four

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

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	06/29/2021 – 07/28/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	10/03/2022 – 11/17/2022
~~XX~~45-day formal or informal comment period with additional ballot	12/05/2022 – 01/18/2023
~~XX~~10-day final ballot	02/13/2023 – 02/22/2023
Board adoption	03/22/2023

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:** **Transmission Relay Loadability**
2. **Number:** PRC-023-~~5~~6
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-~~5~~6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-~~5~~6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-~~5~~6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi- directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with

Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan. See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at

each end of the line.

- An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

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[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

6. ~~Not used.~~Reserved
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
    - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
    - 115% of the highest operator established emergency transformer rating.

    10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
    - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
    - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to

a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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2 As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

3 IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

~~criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)~~

R2. Reserved. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*~~

M2. Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-~~5~~6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~5~~6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-~~5~~6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

~~6~~2

~~by: (i),; (ii)the ,~~

~~C. Measures~~

~~**M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per~~

~~criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)~~

~~M2.~~ Reserved. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)~~

~~**M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)~~

~~**M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)~~

~~**M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)~~

~~**M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-56, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)~~

~~D.~~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 Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning 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, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

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

1.4. Additional Compliance Information

None.

Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	**Reserved.**~~The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.~~

R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.

R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within

		6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after		Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

~~E.~~D. Regional ~~Differences~~Variances

None.

~~F.~~E. ~~Supplemental Technical Reference Document~~Associated Documents

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

   "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Fina l_2008July3.pdf

   NERC Reliability Standard PRC-023-6 Implementation Plan.

   NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	

3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
5	DATE	Add FERC approval history	
6		Revised by Project….	Retired Requirement R2, remove Attachment A, Section/Part 2.3

PRC-023-~~5~~6 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

    1.1. Phase distance.

    1.2. Out-of-step tripping.

    1.3. Switch-on-to-fault.

    1.4. Overcurrent relays.

    1.5. Communications aided protection schemes including but not limited to:

        1.5.1 Permissive overreach transfer trip (POTT).

        1.5.2 Permissive under-reach transfer trip (PUTT).

        1.5.3 Directional comparison blocking (DCB).

        1.5.4 Directional comparison unblocking (DCUB).

    1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current- based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

    2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.

    2.2. Protection systems intended for the detection of ground fault conditions.

    2.3. Reserved.~~Protection systems intended for protection during stable power swings.~~

    2.4. ~~Not used.~~Reserved

    2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

    2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

    2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

    2.8. Relay elements associated with dc lines.

    2.9. Relay elements associated with dc converter transformers.

PRC-023-~~5~~6 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2021-05 Modifications to PRC-023
Reliability Standard PRC-023-6

Applicable Standard(s)

- PRC-023-6 –Transmission Relay Loadability

Requested Retirement(s)

- PRC-023-5 – Transmission Relay Loadability

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

General Considerations

None.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) 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 (ii) the effective date of Reliability Standard PRC-023-5.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) 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 (ii) the effective date of Reliability Standard PRC-023-5.

Retirement Date

The version of Reliability Standard PRC-023 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-023-6.

Initial Performance Date

Each Planning Coordinator shall conduct its first assessment under Reliability Standard PRC-023-6 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-4 or PRC-023-5, whichever occurs first.

Time Period to Address New Designations

Each Transmission Owner, Generator Owner, and Distribution Provider that owns circuits that become applicable to this standard pursyant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Unofficial Comment Form

Project 2021-05 Modifications to PRC-023

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-05 Modifications to PRC-023** by **8 p.m. Eastern, Friday, December 2, 2022.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 404-446-9618.

Background Information

Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking[1] (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their PSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. PSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed or modified because it has been interpreted to restrict the setting of PSB elements making determination of appropriate settings more difficult and making compliance with PRC-026 more difficult. The present inclusion of out of step tripping in Attachment A, Item 1.2 needs to be clarified.

Attachment A exclusion 2.3 should also be removed or modified. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are either not needed or should be modified in the Standard.

The purpose of the proposed project provides a reliability-related benefit by modifying or eliminating PRC-023-4 Requirement R2 to more effectively apply PSB when appropriate to improve BES reliability. Proper application of PSB can also be helpful in complying with PRC-026. It will modify or remove an exclusion (Attachment A – 2.3) that may no longer be needed.

[1] The term power swing blocking (PSB) is also used by industry to describe these elements. The PSB term will be used for the remainder of this SAR.

Questions

1. Do you agree that Reliability Standard PRC-023-4, Requirement R1 "….for all fault conditions…" covers the intent of Requirement R2 so that the Requirement R2 should be retired?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the removal of Section 2.3 from Attachment A?

   ☐ Yes
   ☐ No

   Comments:

3. Provide any additional comments for the standard drafting team to consider, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-05 Modifications to PRC-023-4

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

PRC-023-6

VRF Justification for PRC-023-6, Requirement R1

The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R1

The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R2

The VRF has been removed since this Requirement is retired from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R2

The VSL has been removed since this Requirement is retired from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R3

The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R3

The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R4

The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R4

The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R5

The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R5

The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VRF Justification for PRC-023-6, Requirement R6

The VRF did not change from the previously FERC approved PRC-023-4 Reliability Standard.

VSL Justification for PRC-023-6, Requirement R6

The VSL did not change from the previously FERC approved PRC-023-4 Reliability Standard.

Technical Rationale for Reliability Standard PRC-023-6

October 2022

PRC-023-6 – Transmission Relay Loadability

Rationale for Applicability Section

No changes are proposed to the Applicability of Reliability Standard PRC-023-6 from the prior version.

Rationale for Deletion of Requirement R2

The standard drafting team (SDT) recommends the retirement of PRC-023-5, Requirement R2.

> R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.

The SDT also recommends the retirement of Attachment A, Item 2.3 exclusion:

> 2.3 Protection systems intended for protection during stable power swings [excluded].

Summary of Justification to Retire Requirement R2

- The fault condition regulated by Requirement R2 is also regulated by Requirement R1 and requires the same entity response.
- A significant error in the "Determination and Application of Practical Relaying Loadability Ratings," Appendix C, January 9, 2007 documentation of power swing blocking capabilities appears to have led to development of Requirement R2.
- The development history of Requirement R2 used an incomplete discussion of power swings that appears to have convinced FERC to direct a separate requirement on the subject, rather than accept alternate technical solutions that would assure detection and clearing of faults that may occur during power swings.
- The primary intent of this standard is to address a security aspect of the protection system. Adding a dependability focused requirement in this standard results in confusion in setting the protective relays.
- The roughly 10 years of experience under Requirement R2 has shown that neither compliance, system operations, nor system disturbances have had any significant impact on system reliability. In addition, whatever the original risk addressed by Requirement R2, that is now reduced due to subsequent Protection System upgrades.

Requirement R2 is Effectively Redundant to the Performance Required by R1PRC-023-5 R1 includes the phrase "… prevent its phase protective relay settings from limiting transmission system loadability *while maintaining reliable protection of the BES* ***for all fault conditions***." (emphasis added).

Requirement R2 singles out a specific fault condition when it specifies that the applicable entity "shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1." This is not an expansion of the "… all fault conditions" identified in R1. So if an entity failed to comply with R2, they would also fail to comply with R1.

I. Power Swing Blocking, Appendix C Error

NERC System Protection and Control Task Force (SPCTF) wrote the initial version of PRC-023 Reference Determination and Application of Practical Relaying Loadability Ratings, 8/14/2006. This document was revised on January 9, 2007 and added Appendix C to discuss out of step blocking. This discussion only referenced the type of schemes that are typically implemented using electromechanical relays. The conclusion was that "if (and as long as) a system load condition operates the out-of-step blocking relay, the distance relay will be prevented from operating for a subsequent fault condition. A timer can be added such that the relay issues a trip if the out of step timer does not reset within a defined time." Subsequent versions of this document (2017 is the latest) have not changed this wording. These two sentences appear to be the origin of the item that addressed out of step blocking in PRC-023-1 Attachment A.

The above quoted "… subsequent fault condition!" statement remains true for traditional electromechanical relay schemes. The subsequent (and last) sentence indicates that the (optional?) timer would be used to trip the element. This is not appropriate because tripping should not occur during the identified heavy load conditions unless a fault actually occurs on the element. A timer is not capable of such fault detection.

Appendix C does not discuss why the "… subsequent fault condition!" that became Requirement R2 should be excluded from "… all fault conditions" that remains part of Requirement R1. Given the context of Appendix C, the appropriate conclusion would seem to be that unmodified traditional electromechanical PSB schemes, depending on their settings, may not be able to comply with the R1 or R2 requirements. Unfortunately, the lack of discussion of either "… all fault conditions" or more advanced PSB schemes leaves the impression that there is no acceptable technical solution to this issue.

The present SDT recommends that SPCWG review and update this document and has proposed several edits and additions, including several methods available to protection engineers to remediate the fault identification issues during PSB that were identified by the original drafting team. Some combination of these methods to PSB schemes answers the technical concern to allow tripping for any fault that occurs during a heavy loading condition that results in PSB operation. In combination with the existing wording in R1, this makes the existing R2 redundant and therefore unnecessary.

Therefore the present SDT asserts that no specific reference to power swing blocking is necessary as a PRC-023 requirement, but can be appropriately acknowledged in this Technical Rationale~~,~~ and in a revision to "Determination and Application of Practical Relaying Loadability Ratings," Appendix C.

II. Development History of Requirement R2

The original August 2006 version of PRC-023 Reference Determination and Application of Practical Relaying Loadability Ratings described the standard's objective with respect to faults:

> While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The introduction also included item "1.3 Out-of-Step blocking," but with no further discussion.

The original wording in PRC-023-1, Attachment A regarding power swing blocking was:

> This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

At least one commenter was concerned that this original wording from the PRC-023-1 SDT did not recognize that the PSB can be reset to allow detection of faults after the PSB function asserts. However, the SDT thought no change was necessary. This SDT response does not acknowledge that resetting of the PSB function is even possible.

- **Comment:** Attachment A 2. A word PERMANENTLY should be added before "block trip…"?[1]
    - **Response:** Attachment A 2- Most commenters seemed to understand the intent of this item without further clarification. If an out[-]of-step relay asserts on load and blocks the trip of fault protective relays, and a fault occurs during that loading condition, the out-of-step relay will prevent successful operation of the fault protective relay. (3/9/2007)

Another commenter expressed a related concern for remotely-connected systems. The SDT acknowledged that some scheme modification may be needed but did not describe what a "more complex" scheme would do.

- **Comment:** I am concerned that this standard as drafted would limit the application of out of step block trip functions for remotely-connected systems.[2]
    - **Response:** Attachment A, Item 2 is intended to ensure that facilities are adequately protected for faults. Out-of-step blocking elements may prevent tripping for true faults

[1] Microsoft Word - Consider_Comments_D2_Relay_Loadability_09Mar07.doc (nerc.com), DRAFT 2 comments, pp 41-43

[2] https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_Initial_Ballot_PRC-023_Relay_Loadability_31Jan08.doc, DRAFT 4 Comments, p 16

> during extreme loading conditions. For conditions involving remotely-connected systems, more complex out-of-step blocking schemes may be needed. (1/31/2008)

When FERC reviewed (and eventually approved) the proposed PRC-023-1, an objection was that referencing out of step blocking in Appendix A as a “shall” item was important, but not enforceable because it was not a requirement and had no VSL or VRF. FERC observed the use of this “shall” language and directed that this item be rewritten as a requirement. FERC ordered: (Order 733, paragraph 244)

> We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.

The SDT for PRC-023-2 then proposed to add wording to Requirement R1:

> “. . . and to prevent its out-of-step blocking schemes from blocking tripping for fault conditions.”

One commenter[3] addressed some technical aspects of this specific wording, in part:

> The specific wording proposed by the SDT may prevent using the out-of-step-block functions of many modern and widely used line protection relays (e.g. SEL-321 and later models and GE-UR). These relay’s OSB function first blocks the protection elements from tripping, then uses a short delay and/or other information to determine whether the observed and perhaps evolving condition really represents a fault, in which case the blocking is reset to allow tripping. Such a block/reset operation is the most common technology available and would appear to lie within the intent of FERC in [Order 733] paragraph 244, but could be excluded by the presently proposed language.

Another commenter added[4]:

> “We suggest that the added phrase be removed from R1 and a new requirement created. Suggested wording is “Protection Systems that block for stable swings or out-of-step conditions shall be evaluated to ensure that appropriate tripping will occur for in-section faults that occur during the condition. Some additional delay may be required and is acceptable to ensure that the appropriate tripping occurs.”

The SDT’s conclusion was:

> The SDT agrees and removed out-of-step blocking from Requirement R1. The requirement pertaining to evaluation of out-of-step blocking protection has been moved to a separate

[3] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=018154B3-66E2-5005-8110-C31FAFC91712 pp 169-170
[4] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=018154B3-66E2-5005-8110-C31FAFC91712 p 189

requirement (now Requirement R2) to more clearly delineate this requirement from assessment of relay loadability of phase protective relays.

Both of these commenters suggested what became R2 but did not question whether "… all fault conditions" in R1 already included the faults intended to be detected by R2. It appears that, although NERC is permitted to propose an equally efficient and effective alternative to address a FERC directive, the SDT did not consider any alternate solution to FERC's Order 733 directive to include a separate requirement to detect PSB-related faults.

The SDT's proposed (and eventually approved) Violation Severity Level (VSL) and Violation Risk Factor (VRF) for both PRC-023-2 Requirements R1 and R2 were the same.

The SDT realizes that the meaning of original language in the Attachment A was inverted as it was converted to Requirement R2. The wording was changed from "…shall be evaluated to ensure that they do not block trip …" to "… shall set its out-of-step blocking elements to allow tripping …". This resulted in a significant change in how the Requirement R2 is interpreted by protection engineers. The revised emphasis is on relay settings, rather than evaluation of the PSB scheme itself. The focus shifted from evaluating the PSB scheme to the PSB elements, primarily blinders, which are directly controlled by the settings. In cases of conflict, the remedy was to either not use the PSB scheme or significantly increase the scheme complexity.

At least one entity disabled at least two power swing blocking schemes

- Due to concern whether use of a reset timer would achieve the spirit of Requirement R2 to clear faults within appropriate time.
- The outer PSB characteristic could not be set within the loadability characteristics.

III. Security versus Dependability[5]

The purpose of PRC-023 is:

> Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

The emphasis of PRC-023 is on the security of the transmission system to avoid unnecessary trips during heavy load conditions when no fault occurs. The Purpose and Requirement R1 does include

[5] For the purpose of this discussion the IEEE Standard Dictionary of Electrical and Electronics Terms defines dependability (relay or relay systems) as the facet of reliability that relates to the degree of certainty that a relay or relay system will operate correctly. Similarly, security (relay or relay systems) is the facet of reliability that relates to the degree of certainty that a relay or relay system will not operate incorrectly. Finally, reliability (relay or relay systems) is a measure of the degree of certainty that a relay or relay system will perform correctly. NOTE: Reliability denotes certainty of correct operation together with assurance against incorrect operation from all extraneous causes.

language that "… all fault conditions" (dependability) must be recognized. Requirement R2 carves out a separate dependability item "… to allow tripping of phase protective relays for faults that occur during the loading conditions" as in R1.

The dependability language in R1 is an appropriate balancing of the intent of R1 (security), so mentioning dependability in R1 does not cause confusion. Retiring R2 will make the standard more focused and clear.

IV. Experience with Requirement R2 functionality

Experience is not a perfect guide to judging the necessity of Requirement R2. Absence of evidence is not evidence of absence of failure to clear faults during PSB operations. The approximately 10 years of available history since R2 has been enforceable does provide useful background to judge the scale of potential risk to the bulk power system following R2 retirement. No statistical analysis or antidotal examples can prove that faults will never occur while a relay has asserted its PSB function. However, the extremely small historical occurrence of events that may qualify as faults during a power swing, perhaps as low as zero in this summary, does significantly limit the risk to the bulk power system.

Compliance Violations

A review of compliance violations of the existing Requirement R2 showed only two violations, both discovered about one year after the requirement became enforceable. Both were discovered through review of documentation of relay settings, not from system operations. In both cases the associated Risk Description indicated that the issues posed minimal risk to the reliability of the bulk power system.

An audit finding was due to a 12% deviation from the required loadability and only affected one of the two redundant protection systems. The entity re-calculated their relay settings and found no other related issues on their system.

A self-report identified that one of three redundant protection schemes on each of three transmission lines was impacted by an OSB calculation error. Relay settings on the other two protection schemes for each transmission line were not impacted and acceptable fault clearing would have occurred even if the loading conditions specified in PRC-023-2 R1 were to occur simultaneously with a three-phase fault on the line.

It does not appear that any risk was imposed to the Bulk Power System from these violations, or even whether failure of one of two or three redundant relays to trip for a fault would have constituted a Misoperation since the Composite Protection System would have operated correctly.

Outage and Misoperation Experience

The SDT reviewed TADS and MIDAS data for misoperations involving three phase faults which are more likely to result in power swings and are the events regulated by Requirement R2. For the approximately 5 years of reliable MIDAS data covering about 40,000 total operations, only 11 possible events were discovered, and only a single event involved relays. From the available event descriptions it is not clear that Requirement R2 prevented any of these events.

Major System Disturbances

The NERC Event Analysis web site includes reports for 18 major events. The SDT was also able to review the FRCC disturbance of February 26, 2008 (not listed on the NERC site). These reports were reviewed to discover whether any system impacts were identified from faults during relay power swing block operations. The time range of these events starts before R2 was enforceable until summer 2021. The short summary is that Requirement R2 does not seem to have improved or detracted from system performance during any of these major system disturbances.

Several event reports describe the issues that have been noted regarding PV (lack of) ride through capability during voltage sags associated with fault clearing. There are significant overlapping causes associated with these events. However, these reports describe nothing related to power swings or PSB.

- **June-August 2021 CAISO Solar PV Disturbance Report**
- **May/June 2021 Odessa Disturbance Report**
- **July 2020 San Fernando Solar PV Reduction Disturbance Report**
- **April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report**
- **October 2017 Canyon 2 Fire Disturbance Report**
- **August 2016 1200 MW Fault Induced Solar Photovoltaic Resources Interruption Disturbance Report**

Several event reports cover system performance during cold weather events, hurricanes, and other major weather conditions. Most system impacts resulted from physical damage. None of these reports identified any system impacts due to faults during power swings or power swing blocking. Protection System impacts from all of these events ranged from very minor to none.

- **Cold Weather Training Materials**
    - This is guidance material for preparation and response rather than an event description.
- **January 2014 Polar Vortex Review**
- **October 2012 Hurricane Sandy Event Analysis Report**
- **October 2011 Northeast Snowstorm Event**
    - One relay misoperation was identified, though the specific cause was not described. However, many transmission outages did not destabilize the BPS or regional systems.
- **January 2018 South Central Cold Weather Event Report**
    - Large scale impacts to generation capability, but no specific faults involved, no PSB involved, no recommendation regarding protection against transmission power swings
- **September 2017 Hurricane Irma Event Analysis Report**

- More than 100 storm forced transmission outages and 3300 MW forced plant outages. There were no identified misoperations that contributed to BPS facilities being out of service during the storm.

- **August 2017 Hurricane Harvey Event Analysis Report**
  - About 225 transmission assets impacted, maximum 21+ GW generation unavailable (ERCOT + MISO). No noted protection system misoperations, power swings, or PSB.

Several events had more traditional and direct electrical causes, but none indicated any power system impact due to faults during power swing blocking conditions.

- **January 2019 Eastern Interconnection Forced Oscillation Event Report**
  - PT failure at a Florida plant induced oscillations throughout the Eastern Interconnection: 200 MW swings at the plant, 50 MW in New England. No faults involved, no PSB involved, no recommendation regarding protection against transmission power swings.
- **April 2015 Washington D.C. Area Low-Voltage Disturbance Event**
  - 58 second fault clearing resulting from equipment failure and protection system misoperations of two auxiliary tripping systems. Recommendations relate to trip auxiliary design and breaker failure initiate. No noted impacts from power swings or PSB.
- **September 2011 Southwest Blackout Event**
  - FERC/NERC Staff Report on the September 8, 2011 Blackout affecting Arizona and Southern California identified that large open circuit angles were not monitored for particular facilities in Arizona to determine whether closing could be safely accomplished. However, this result affected restoration rather than resulting from any power swing on the system, so did not involve PSB. The San Onofre nuclear plant also tripped on turbine control logic as local frequency spiked above 61 Hz. No fault or tripping was associated with a power swing or PSB.
- **FRCC System Disturbance**
  - The FRCC disturbance of February 26, 2008 included a zone 1 trip during a power swing (PSB was not applied) but was roughly the 15^{th} event in the disturbance sequence. The report did not recommend any related protection system changes.
- **August 2003 Northeast Blackout Event**
  - The Northeast blackout of August 14, 2003 did involve a few out of step line trips on distance relay elements late in the event sequence that may have been prevented by application of PSB. However, the entire event did not include any case of failure to clear a fault due to PSB relay elements failing to reset under relay loadability conditions described in PRC-023.

Protection System Improvements

Most entities have continued to replace electromechanical, solid state, and early generations of microprocessor relays with newer microprocessor relays since Requirement R2 became effective. The effect of these upgrades is that these newer relays can more easily comply with the intent of the original wording in Appendix A of PRC-023-1. This upgrade process further reduces any risk that is intended to be addressed by Requirement R2. For example, one entity that extensively applies PSB and out of step tripping on its transmission system began 2011 with 161 of 471 (34%) of affected line terminals protected by these lower capability (electromechanical) relays. By 2022 only 19 of 699 (2.7%) of the affected line terminals were still protected by these less capable relays. A second entity has upgraded all of their out of step applications to modern microprocessor-based schemes. A third entity has upgraded all of its out of step applications above 200 kV to modern microprocessor relays and has only a single electromechanical application still in service at 115 kV.

Justification to Retire Attachment A, Item 2.3 Exclusion

Attachment A item 2.3 excludes “Protection systems intended for protection during stable power swings”. This exclusion is referencing “Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations”[6]. Florida was cited in the record of development as an example of where these schemes were employed. Research has indicated that these schemes no longer exist and there is no need for a power swing tripping exclusion. PRC-026 covers stable power swings adequately. Since Item 2.3 is an exclusion, there is no overlap with PRC-026.

The original PRC-023-1 SDT response to comments included the following statements:

- (12) In some parts of North America (for example Florida), there are relay systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other to maintain desirable performance …. [footnote 6, p 48]
- Where out of step tripping or blocking relays are applied independently within the system they must comply with the standard. [footnote 6, p 55]

The normal practice for power systems generally should not be to intentionally separate during stable power swings. It is the understanding of the present SDT that the example scheme from Florida is no longer used. The second bullet response seems to say that exclusion 2.3 should never have been included.

The present SDT asserts that Attachment A, Item 2.3 can be safely retired without creating a reliability gap.

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[6] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

Appendix C — Out-of-step Blocking Relaying

Out-of-step blocking, also known as power swing blocking (PSB), is sometimes applied on transmission lines and transformers to prevent tripping of the circuit element for predicted (by transient stability or other studies) or observed power system swings.

There are many methods of providing the out-of-step blocking function; one common approach, used with distance relays, uses between one and three impedance characteristics approximately concentric with the tripping characteristic. These characteristics may be circular, quadrilateral, or other shapes.

During normal system conditions the accelerating power, Pa, will be essentially zero. During system disturbances, Pa > 0. Pa is the difference between the mechanical power input, Pm, and the electrical power output, Pe, of the system, ignoring any losses. The machines or group of machines will accelerate uniformly at the rate of Pa/2H radians per second squared, where H is the inertia constant of the system. During a fault condition Pa is much greater than 1 resulting in a near instantaneous change from load to fault impedance. During a stable swing condition, Pa < 1, resulting in a slower rate of change of impedance.

For a system swing condition, the apparent impedance will form a loci of impedance points (relative to time) which changes relatively slowly at first; for a stable swing (where no generators “slip poles” or go unstable), the impedance loci will eventually damp out to a new steady-state operating point. For an unstable swing, the impedance loci will change quickly traversing the jx-axis of the impedance plane as the generator slips a pole as shown in Figure C-1 below.

For simplicity, this appendix discusses the concentric-distance-characteristic method of out-of-step blocking, considering circular mho characteristics, most commonly used with electromechanical relays. As mentioned above, this approach uses a mho characteristic for the out-of-step blocking relay, which is larger than and approximately concentric to the related distance relay characteristic. The out-of-step blocking characteristic is also equipped with a timer, such that a fault will transit the out-of-step blocking characteristic too quickly to operate the out-of-step blocking relay, but a swing will reside between the out-of-step blocking characteristic and the tripping characteristic for a sufficient period of time for the out-of-step blocking relay to operate. Operation of the out-of-step blocking relay (including the timer) will in turn inhibit the distance relay from operating. More sophisticated schemes differentiate between a swing and a heavy load condition by using a second timer that identifies that the impedance stays inside the outer load blinder, which is not characteristic of a swing, and unblocks the scheme. Often, this unblocking timer is built into the scheme logic and is not user settable.

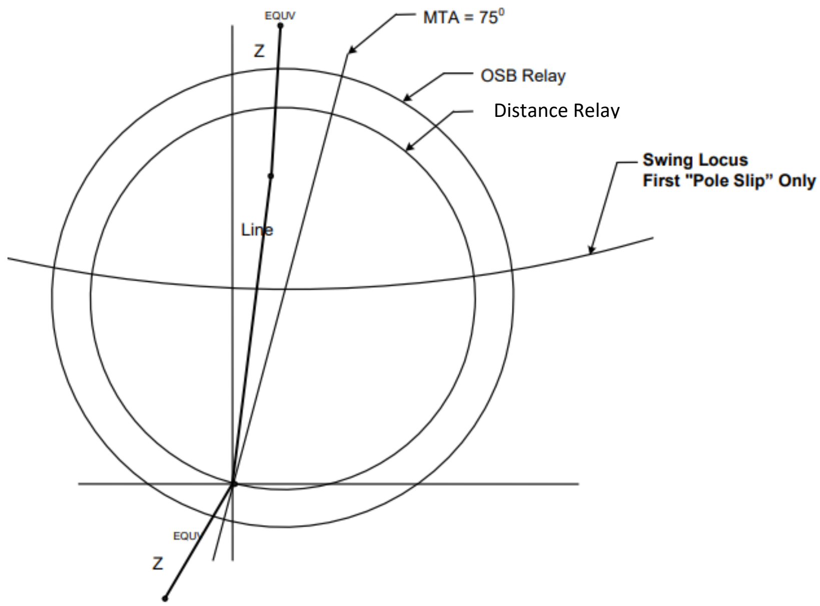

Figure C-1: Portion of an Unstable Swing

Figure C-1 illustrates the relationship between the out-of-step blocking relay and the distance relay and shows a sample of a portion of an unstable swing.

Impact of System Loading of the Out-of-Step Relaying

Figure C-2 illustrates a distance relay and out-of-step blocking relay and shows the relative effects of several apparent impedances.

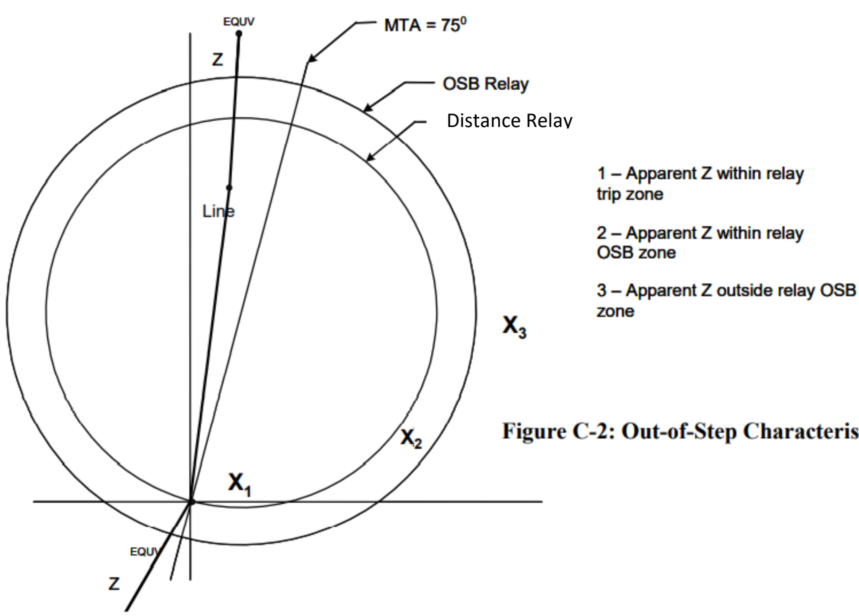

Figure C-2: Out-of-Step Characteristics with Load

Both the distance relay and the out-of-step blocking relay have characteristics responsive to the impedance that is seen at the line terminal. The distance relays must be considered when evaluating the effect of system loads on relay characteristics (usually referred to as "relay loadability"). However, when the behavior of out-of-step blocking relays is also considered, it becomes clear that they must also be included in the evaluation of system loads, as their resistive reach must necessarily be longer than that of the distance relays, making them even more responsive to load.

Three different load impedances are shown. Load impedance (1) shows an impedance (either load or fault) which would operate the distance relay. Load impedance (3) shows a load impedance well outside both the tripping characteristic and the out-of-step blocking characteristic and illustrates the desired result. The primary concern relates to the fact that, if an apparent impedance, shown as load impedance (2), resides within the out-of-step blocking characteristic (but outside the tripping characteristic) for the duration of the out-of-step blocking timer, the out-of-step blocking relay inhibits the operation of the distance relay. It becomes clear that such an apparent impedance can represent a system load condition as well as a system swing; if (and as long as) a system load condition operates the out-of-step blocking relay, the distance relay will be prevented from operating for a subsequent fault condition.

Several techniques are commonly used by some solid state and many microprocessor relays, singly or in combination, to mitigate such “permanent” out of step blocking. Several, though not all, possible methods are briefly described here. These methods assure detection and clearing of all faults will occur during any of the loading conditions of PRC-023 R1.

- One mitigation method uses a timer to detect that the measured impedance remains between the blinders for a period that is longer than is characteristic of a swing, and unblocks the scheme. Often, this unblocking timer is built into the scheme logic and is not user settable. This method can also be used with electromechanical relays and some solid state relays.
- The out of step algorithm may monitor the time that the impedance locus remains within an inner blinder region to reset the blocking using an adaptive timer based on the swing rate.
- The out of step algorithm may monitor negative and/or zero sequence currents and reset the out of step blocking for a significant unbalance.
- Distance protection may use quadrilateral or other non-mho shapes to allow smaller resistive reach settings for both protection and out of step characteristics that do not encroach on the relay loadability characteristic.
- Out of step characteristics that use quadrilateral or modified mho shapes may be set with shorter resistive reach that encroaches on the distance relay protection mho characteristics and use relay logic to only allow trips when the impedance locus is within both the protection and out of step characteristic.
- The out of step algorithm may continuously monitor parameters such as swing center voltage, currents, or impedance to determine whether out of step blocking should be asserted. Continuous monitoring prevents “permanent” out of step blocking by automatically resetting if the apparent impedance locus stops moving, as is characteristic of a fault.
- Other techniques may also be used.

Appendix C — Out-of-step Blocking Relaying

Out-of-step blocking, also known as power swing blocking (PSB), is sometimes applied on transmission lines and transformers to prevent tripping of the circuit element for predicted (by transient stability or other studies) or observed power system swings.

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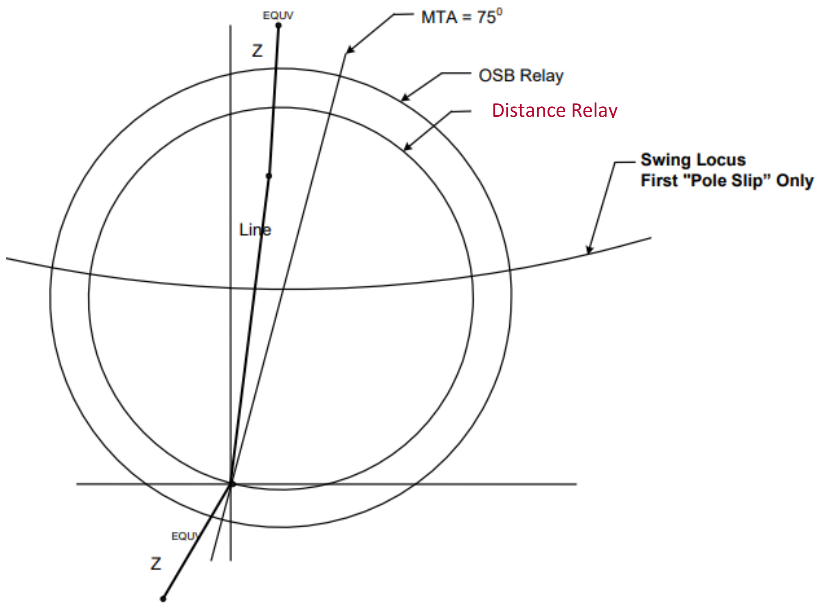
During normal system conditions the accelerating power, Pa, will be essentially zero. During system disturbances, Pa > 0. Pa is the difference between the mechanical power input, Pm, and the electrical power output, Pe, of the system, ignoring any losses. The machines or group of machines will accelerate uniformly at the rate of Pa/2H radians per second squared, where H is the inertia constant of the system. During a fault condition Pa is much greater than~~>>~~ 1 resulting in a near instantaneous change from load to fault impedance. During a stable swing condition, Pa < 1, resulting in a slower rate of change of impedance.

For a system swing condition, the apparent impedance will form a loci of impedance points (relative to time) which changes relatively slowly at first; for a stable swing (where no generators "slip poles" or go unstable), the impedance loci will eventually damp out to a new steady-state operating point. For an unstable swing, the impedance loci will change quickly traversing the jx-axis of the impedance plane as the generator slips a pole as shown in Figure C-1 below.

For simplicity, this appendix discusses the concentric-distance-characteristic method of out-of-step blocking, considering circular mho characteristics, most commonly used with electromechanical relays. As mentioned above, this approach uses a mho characteristic for the out-of-step blocking relay, which is larger than and approximately concentric to the related ~~tripping~~ distance relay characteristic. The out-of-step blocking characteristic is also equipped with a timer, such that a fault will transit the out-of-step blocking characteristic too quickly to operate the out-of-step blocking relay, but a swing will reside between the out-of-step blocking characteristic and the tripping characteristic for a sufficient period of time for the out-of-step blocking relay to ~~trip~~operate. Operation of the out-of-step blocking relay (including the timer) will in turn inhibit the ~~tripping~~ distance relay from operating.~~ This timer may be fixed or settable, generally in the range of 2-4 cycles. More sophisticated schemes differentiate between a swing and a heavy load condition by using a second timer that identifies that the impedance did not cross the inner characteristic.~~ More sophisticated schemes differentiate between a swing and a heavy load condition by using a second timer that identifies that the impedance stays inside the outer load blinder, which is not characteristic of a swing, and unblocks the scheme. Often, this unblocking timer is built into the scheme logic and is not user settable.



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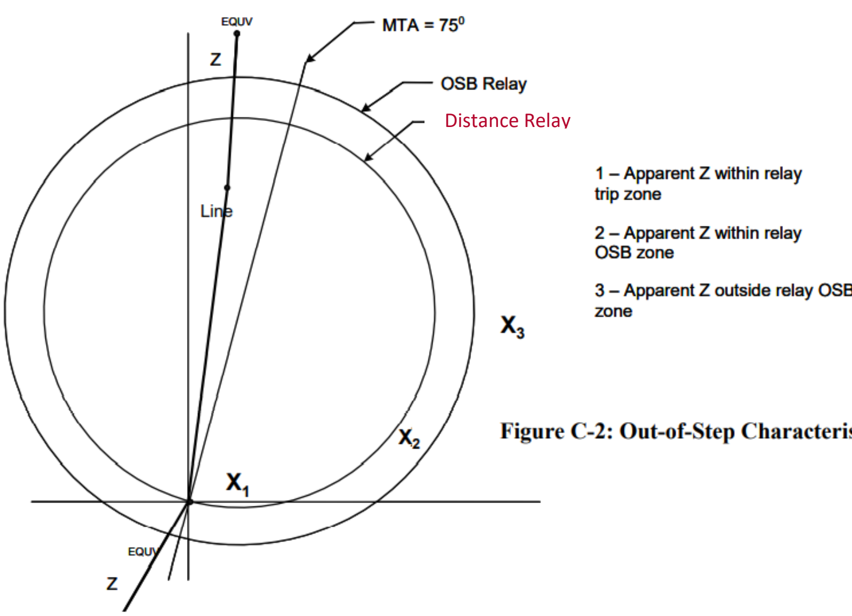

Figure C-2: Out-of-Step Characteristics with Load

Both the ~~tripping~~ distance relay and the out-of-step blocking relay have characteristics responsive to the impedance that is seen ~~by the distance relay~~at the line terminal. ~~In general, only~~ The ~~tripping~~ distance relays must be~~are~~ considered when evaluating the effect of system loads on relay characteristics (usually referred to as “relay loadability”). However, when the behavior of out-of-step blocking relays is also considered, it becomes clear that they must also be included in the evaluation of system loads, as their resistive reach must necessarily be longer than that of the ~~tripping~~ distance relays, making them even more responsive to load.

Three different load impedances are shown. Load impedance (1) shows an impedance (either load or fault) which would operate the ~~tripping~~ distance relay. Load impedance (3) shows a load impedance well outside both the tripping characteristic and the out-of-step blocking characteristic~~,~~ and illustrates the desired result. The primary concern relates to the fact that, if an apparent impedance, shown as load impedance (2), resides within the out-of-step blocking characteristic (but outside the tripping characteristic) for the duration of the out-of-step blocking timer, the out-of-step blocking relay inhibits the operation of the ~~tripping~~ distance relay. It becomes clear that such an apparent impedance can represent a system load condition as well as a system swing; if (and as long as) a system load condition operates the out-of-step blocking relay, the ~~tripping~~ distance relay will be prevented from operating for a subsequent fault condition.~~! A timer can be added such that the relay issues a trip if the out of step timer does not reset within a defined time.~~

Several techniques are commonly used by some solid state and many microprocessor relays, singly or in combination, to mitigate such "permanent" out of step blocking. Several, though not all, possible methods are briefly described here. These methods assure detection and clearing of all faults will occur during any of the loading conditions of PRC-023 R1.

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- Out of step characteristics that use quadrilateral or modified mho shapes may be set with shorter resistive reach that encroaches on the distance relay protection mho characteristics and use relay logic to only allow trips when the impedance locus is within both the protection and out of step characteristic.
- The out of step algorithm may continuously monitor parameters such as swing center voltage, currents, or impedance to determine whether out of step blocking should be asserted. Continuous monitoring prevents "permanent" out of step blocking by automatically resetting if the apparent impedance locus stops moving, as is characteristic of a fault.
- Other techniques may also be used.

Standards Announcement

Project 2021-05 Modifications to PRC-023

Formal Comment Period Open through December 2, 2022
Ballot Pools Forming through November 15, 2022

Now Available

A formal comment period is open through **8 p.m. Eastern, Friday, December 2, 2022** for the following:

- PRC-023-6 – Transmission Relay Loadability
- PRC-023-6 Implementation Plan

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Tuesday, November 15, 2022.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the standard and implementation plan, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 23 – December 2, 2022**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-05 Modifications to PRC-023” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2021-05 Modifications to PRC-023 | Draft 1
Comment Period Start Date:	10/10/2022
Comment Period End Date:	12/5/2022
Associated Ballots:	2021-05 Modifications to PRC-023 PRC-023-6 | Implementation Plan IN 1 OT 2021-05 Modifications to PRC-023 PRC-023-6 IN 1 ST

There were 54 sets of responses, including comments from approximately 142 different people from approximately 97 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree that Reliability Standard PRC-023-4, Requirement R1 "….for all fault conditions…" covers the intent of Requirement R2 so that the Requirement R2 should be retired?

2. Do you agree with the removal of Section 2.3 from Attachment A?

3. Provide any additional comments for the standard drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	SRC 2022	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Matt Goldberg	ISONE	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
Portland General Electric Co.	Daniel Mason	6		Portland General Electric Co.	Brooke Jockin	Portland General Electric Co.	1	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC
					Ryan Olson	Portland General Electric Co.	5	WECC
					Daniel Mason	Portland General Electric Co	6	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Amber Skillern	East Kentucky Power Cooperative	1	SERC

					Ryan Strom	Buckeye Power, Inc.	5	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Patricia Ireland	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Public Utility District No. 1 of Chelan County	Meaghan Connell	5		PUD No. 1 of Chelan County	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
					Meaghan Connell	Public Utility District No. 1 Chelan County	5	WECC
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC

					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
NPCC	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Sheraz Majid	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					John Hastings	National Grid	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC

Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
Dan Kopin	Vermont Electric Power Company	1	NPCC
James Grant	NYISO	2	NPCC
John Pearson	ISO New England, Inc.	2	NPCC
Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
Randy MacDonald	New Brunswick Power Corporation	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Michael Jones	National Grid	3	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC

					Glen Smith	Entergy Services	4	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC

					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree that Reliability Standard PRC-023-4, Requirement R1 "….for all fault conditions…" covers the intent of Requirement R2 so that the Requirement R2 should be retired?

Brian Lindsey - Entergy - 1

Answer	No
Document Name	
Comment	
Agree that R2 is unnecessary but it is not the same as R1. R1 does not preclude out-of-stop blocking outside the 150% load region. R2 does. Therefore, they are not the same.	
Likes 0	
Dislikes 0	
Response	

Michael Brytowski - Great River Energy - 3

Answer	No
Document Name	
Comment	
These comments were submitted incorrectly. Please ignore.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees wtih EEI comments.	
Likes 0	
Dislikes 0	

Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with the retirement of Requirement R2 since the "… for all fault conditions…" in Requirement R1 covers the intent of R2.	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
I agree that retirement R2 should be retired as R1 already covers the intent of R2.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees that R1 covers the intent of R2 and therefore agrees with the retirement of R2	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	Yes

Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
The requirement R2 and the attachment A 2.3 cause interpretation confusion and the proposal to remove both from the requirements would allow the normal functioning of the OOSB relays during power swing conditions	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	

Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
EEI agrees that the language in R1 that states that “for all fault conditions” is sufficient to cover the intent of Requirement R2, so that R2 can be retired.	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	

Randall Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

John Daho - John Daho On Behalf of: David Weekley, MEAG Power, 3, 1; - John Daho

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Loiacano - Arkansas Electric Cooperative Corporation - 1 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the removal of Section 2.3 from Attachment A?

Michael Brytowski - Great River Energy - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #2.	
Likes 0	
Dislikes 0	

Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the removal of Section 2.3 from Attachment A.	
Likes 0	
Dislikes 0	

Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by EEI	
Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
The requirement R2 and the attachment A 2.3 cause interpretation confusion and the proposal to remove both from the requirements would allow the normal functioning of the OOSB relays during power swing conditions	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	

Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with the removal of Section 2.3 from Attachment A.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with the removal of Attachment A, Section 2.3 exclusion since it is related to Requirement R2 which is being retired.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Black Hills Corporation (BHP) agrees wtih EEI comments.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennifer Loiacano - Arkansas Electric Cooperative Corporation - 1 - MRO,SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Daho - John Daho On Behalf of: David Weekley, MEAG Power, 3, 1; - John Daho	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Randall Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

3. Provide any additional comments for the standard drafting team to consider, if desired.

Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI's additional comment.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI's additional comments.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E wishes to thank the Standard Drafting Team (SDT) for their efforts on the modification work and has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Consider comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
nothing further at this time	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	
Document Name	
Comment	
Regarding the deletion of Requirement R2 if deleted from this PRC standard, it should be added to another PRC standard where the SDT may opine on its insertion subject to review by stakeholders before finalization of deletion from this Standard.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	
Document Name	
Comment	

- Section D1.2 (Data Retention): 1st paragraph, sentence should end with a period instead of a semi-colon.
- Please considering updating section C. Compliance to use the most up-to-date version of the NERC wording for section C. Compliance. The wording used in Section C. Compliance, for draft 1 of PRC-023-6, is obsolete.
- Please consider adding the Planning Coordinator to the Applicable Entities list in the Implementation Plan.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

No additional comments

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3

Answer	
Document Name	

Comment

1. Black Hills Corporation (BHP) agrees with EEI's additional comment.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

FirstEnergy supports EEI's comments which states:

Under Section B. (Associated Documents) the following document is Referenced: "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008." However, the hyperlink appears to broken and the associated document has not been included in the documents to be reviewed by the industry, except for Appendix C. While Appendix C a portion of this document that is of greatest concern, the entire document should be revised, updated and attached for industry review.

The Compliance Section of PRC-023-6 does not appear to conform to the latest approved language that is to be used in new or revised Reliability Standards. Please update this section to conform to the current Compliance language for NERC Reliability Standards.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 5

Answer	
Document Name	

Comment

- Section C1.2 (Data Retention): 1st paragraph, sentence should end with a period instead of a semi-colon.
- Please considering updating section C. Compliance to use the most up-to-date version of the NERC wording for section C. Compliance. The wording used in Section C. Compliance, for draft 1 of PRC-023-6, is obsolete.
- Please consider adding the Planning Coordinator to the Applicable Entities list in the Implementation Plan.
- Section "Regional Variances" and "Associated Documents" should be sections D. and E. and not A. and B. as seen in the clean version. (Redlines are ok)

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	
Document Name	

Comment

Black Hills Corporation (BHP) agrees with EEI's additional comment.

Likes 0	
Dislikes 0	

Response

Darcy O'Connell - California ISO - 2	
Answer	
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends using NERC Glossary terms where appropriate or defining terms that are not clearly defined in the NERC Glossary. For example, criteria numbers 8 and 9 under Requirement R1 use the term “highest operator established emergency transformer rating”, and criterion number 9 also uses the term “maximum applicable nameplate rating”. Neither of these terms exist in the NERC Glossary, though the terms Emergency Rating and Rating do exist in the NERC Glossary.

In Section C 1.2, Texas RE noticed the use of the term Data Retention. It appears that other proposed standards are using the term Evidence Retention as in proposed Reliability Standards CIP-012-2, VAR-002-5, MOD-026-2, IRO-010-5, and TOP-003-6.

Texas RE noticed that Section C 1.3 Compliance Monitoring and Enforcement Processes differs from Section C1.3 in other currently proposed standards, where it describes the Compliance Monitoring and Enforcement Program. Is this the SDT’s intent?

Texas RE has the following comments on Attachment B:

- The first bullet in “Circuits to evaluate” needs a space between “200” and “kv”
- Criteria B1 does not mention the ERCOT Interconnection. Is this the SDT’s intent?
- The footer page numbers need corrected (“Page 17 of 16”)
- Since Criterion B3 is referring to NUC-001, is “Transmission Entity” referring to Transmission Entity as described in section A 4 of NUC-001-4?

In the Implementation Plan, under Time Period to Address New Designations, correct “pursyant” to “pursuant”.

It is unclear what the “applicable effective date” is referencing since, presumably, a “New Designation” under PRC-023-6 would only occur after the effective date of PRC-023-6.

Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	
Document Name	
Comment	

Portland General Electric Company supports the comments provided by EEI.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon supports the comments submitted by EEI

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI offers the following additional input for SDT consideration:

Under Section B. (Associated Documents) the following document is Referenced: "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008." However, the hyperlink appears to be broken and the associated document has not been included in the documents to be reviewed by the industry, except for Appendix C. While Appendix C a portion of this document that is of greatest concern, the entire document should be revised, updated and attached for industry review.

The Compliance Section of PRC-023-6 does not appear to conform to the latest approved language that is to be used in new or revised Reliability Standards. Please update this section to conform to the current Compliance language for NERC Reliability Standards.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no additional comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

Change Data Retention Section 1.2 to:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 since the last audit period.

Section D1.2 (Data Retention): In 1st paragraph, the sentence should end with a period instead of a semi-colon.

Please consider updating section C. Compliance to use the most up-to-date version of the NERC wording for section C. Compliance. The wording used in Section C. Compliance, for draft 1 of PRC-023-6, is obsolete.

Please consider adding the Planning Coordinator to the Applicable Entities list in the Implementation Plan.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment

SPP recommend that the drafting team revise the current/future comment form to reflect the appropriate standard version so, it aligns with documentation posted to the NERC page. For example, the one stop shop details for PRC-023-4 shows that this standard became effective on April 1, 2017 with an inactive date of March 31, 2024. However, PRC-023-5 will becomes effective April 1, 2024. Our interpretation is that all proposed changes would be associated with PRC-023-5 instead of PRC-023-4 in which the background information and the comment form suggests on the project page. Additionally, the redline document suggests that PRC-023-5 is the appropriated document to be mentioned in the background information. From our perspective, this creates confusion on which document is being used to support the drafting teams efforts.

Additionally, SPP recommends the drafting team further develop the physical document for the Technical Rationale associated with the PRC-023-6 Standard by including rationale for the legacy requirements. The link located in the “Associated Documents” sections of both PRC-023-5 (Project 2015-09) and PRC-023-6 (proposed) appears to not work properly to grant access to this data, which will create issues for industry. Moreover, there was a NERC project conducted to remove all Technical Rationale and Guidelines and Technical Basis from the back of all standards and put into structured independent formatted documentation. From our perspective, a link in the Associated Documents section of the standard in place of a separate Technical Rationale document doesn’t align with NERCs intent for drafting teams and their development of quality independent documentation. The

proposed Technical Rationale document for PRC-023-6 should be updated to include the information that is associated with the link described above to be consistent with the current template for standards.	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	
Document Name	
Comment	
The IRC SRC supports improvements to clarify requirements on how Out-of-Step Blocking protection schemes should work. The proposed changes will provide more certainty in how these schemes will perform to reduce exposure to islanding. We do ask NERC to consider the implementation schedule and need for these changes in the context of the numerous other standards being developed and anticipated to be adopted. As described in the Technical Rationale, situations where OOSB relays may have not been correctly coordinated have seen little direct impact on system reliability. If this initial ballot fails and industry needs to expend more resources to review changes to reach consensus, we ask NERC to consider the immediacy of these changes relative to other risks where PRC requirements revisions are needed. Industry protection schemes expertise should be focused on the greatest reliability threats.	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2021-05 Modifications to PRC-023 | Draft 1
Comment Period Start Date:	10/10/2022
Comment Period End Date:	12/5/2022
Associated Ballot(s):	2021-05 Modifications to PRC-023 PRC-023-6 | Implementation Plan IN 1 OT 2021-05 Modifications to PRC-023 PRC-023-6 IN 1 ST

There were 54 sets of responses, including comments from approximately 142 different people from approximately 97 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Vice President of Engineering and Standards Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Do you agree that Reliability Standard PRC-023-4, Requirement R1 "….for all fault conditions…" covers the intent of Requirement R2 so that the Requirement R2 should be retired?

2. Do you agree with the removal of Section 2.3 from Attachment A?

3. Provide any additional comments for the standard drafting team to consider, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	SRC 2022	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Matt Goldberg	ISONE	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
Portland General Electric Co.	Daniel Mason	6		Portland General Electric Co.	Brooke Jockin	Portland General Electric Co.	1	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Adam Menendez	Portland General Electric Co.	3	WECC
					Ryan Olson	Portland General Electric Co.	5	WECC
					Daniel Mason	Portland General Electric Co	6	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Shari Heino	Brazos Electric Power	5	Texas RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative, Inc.		
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Patricia Ireland	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Public Utility District No. 1 of Chelan County	Meaghan Connell	5		PUD No. 1 of Chelan County	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
					Meaghan Connell	Public Utility District No. 1 Chelan County	5	WECC
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
NPCC	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Sheraz Majid	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					John Hastings	National Grid	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Dan Kopin	Vermont Electric Power Company	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Associated Electric	Todd Bennett	3		AECI	Michael Bax	Central Electric Power	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Cooperative, Inc.						Cooperative (Missouri)		
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative, Inc.		
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative, Inc.		
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree that Reliability Standard PRC-023-4, Requirement R1 "….for all fault conditions…" covers the intent of Requirement R2 so that the Requirement R2 should be retired?	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
Agree that R2 is unnecessary but it is not the same as R1. R1 does not preclude out-of-stop blocking outside the 150% load region. R2 does. Therefore, they are not the same.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. We agree that R1 and R2 are not the same, but it wasn't the intent of the SDT to imply that. The SDT feels that the dependability statement in R1 covers the fault conditions of R2.	
Michael Brytowski - Great River Energy - 3	
Answer	No
Document Name	
Comment	
These comments were submitted incorrectly. Please ignore.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT will comply with your request.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees wtih EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with the retirement of Requirement R2 since the "… for all fault conditions…" in Requirement R1 covers the intent of R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
I agree that retirement R2 should be retired as R1 already covers the intent of R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

FirstEnergy agrees that R1 covers the intent of R2 and therefore agrees with the retirement of R2	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments.	

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
The requirement R2 and the attachment A 2.3 cause interpretation confusion and the proposal to remove both from the requirements would allow the normal functioning of the OOSB relays during power swing conditions	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that the language in R1 that states that "for all fault conditions" is sufficient to cover the intent of Requirement R2, so that R2 can be retired.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Randall Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Daho - John Daho On Behalf of: David Weekley, MEAG Power, 3, 1; - John Daho	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Loiacano - Arkansas Electric Cooperative Corporation - 1 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Robert Follini - Avista - Avista Corporation - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carl Pineault - Hydro-Qu?bec Production - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

2. Do you agree with the removal of Section 2.3 from Attachment A?

Michael Brytowski - Great River Energy - 3	
Answer	No
Document Name	
Comment	
Thank you for your participation. We are not sure how to answer your concern.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	Yes
Document Name	
Comment	
EEI supports the removal of Section 2.3 from Attachment A.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
The requirement R2 and the attachment A 2.3 cause interpretation confusion and the proposal to remove both from the requirements would allow the normal functioning of the OOSB relays during power swing conditions	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with the removal of Section 2.3 from Attachment A.	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with the removal of Attachment A, Section 2.3 exclusion since it is related to Requirement R2 which is being retired.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes

Document Name	
Comment	
Black Hills Corporation (BHP) agrees wtih EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Loiacano - Arkansas Electric Cooperative Corporation - 1 - MRO,SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Daho - John Daho On Behalf of: David Weekley, MEAG Power, 3, 1; - John Daho	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Randall Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

3. Provide any additional comments for the standard drafting team to consider, if desired.
Brian Lindsey - Entergy - 1

Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with EEI's additional comment.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	

Black Hills Corporation (BHP) agrees with EEI's additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to Mark Gray of EEI.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E wishes to thank the Standard Drafting Team (SDT) for their efforts on the modification work and has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Consider comments provided by EEI.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to Mark Gray of EEI.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
nothing further at this time	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	
Document Name	
Comment	
Regarding the deletion of Requirement R2 if deleted from this PRC standard, it should be added to another PRC standard where the SDT may opine on its insertion subject to review by stakeholders before finalization of deletion from this Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT does not agree that the content of R2 needs to be included in another standard. This was reviewed at greater length in the Technical Rationale.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	

Answer	
Document Name	
Comment	
• Section D1.2 (Data Retention): 1st paragraph, sentence should end with a period instead of a semi-colon. • Please considering updating section C. Compliance to use the most up-to-date version of the NERC wording for section C. Compliance. The wording used in Section C. Compliance, for draft 1 of PRC-023-6, is obsolete. • Please consider adding the Planning Coordinator to the Applicable Entities list in the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments • The SDT will make the [;] ➔ [.] correction. • EEI had a similar comment on the Compliance Section, but the SDT believes this change is outside the scope of the present SAR. • The SDT has added the Planning Coordinator to the Implementation Plan's Applicable Entities.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	

Answer	
Document Name	
Comment	
1. Black Hills Corporation (BHP) agrees with EEI's additional comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to Mark Gray of EEI.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy supports EEI's comments which states: Under Section B. (Associated Documents) the following document is Referenced: "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008." However, the hyperlink appears to broken and the associated document has not been included in the documents to be reviewed by the industry, except for Appendix C. While Appendix C a portion of this document that is of greatest concern, the entire document should be revised, updated and attached for industry review. The Compliance Section of PRC-023-6 does not appear to conform to the latest approved language that is to be used in new or revised Reliability Standards. Please update this section to conform to the current Compliance language for NERC Reliability Standards.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Please refer to the SDT's response to Mark Gray of EEI.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
• Section C1.2 (Data Retention): 1st paragraph, sentence should end with a period instead of a semi-colon. • Please considering updating section C. Compliance to use the most up-to-date version of the NERC wording for section C. Compliance. The wording used in Section C. Compliance, for draft 1 of PRC-023-6, is obsolete. • Please consider adding the Planning Coordinator to the Applicable Entities list in the Implementation Plan. • Section "Regional Variances" and "Associated Documents" should be sections D. and E. and not A. and B. as seen in the clean version. (Redlines are ok)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments • The SDT will make the [;] ➔ [.] correction. • EEI had a similar comment on the Compliance Section, but the SDT believes that this change is outside the scope of the present SAR. • The SDT has added the Planning Coordinator to the Implementation Plan's Applicable Entities. • The SDT believes that this change is outside the scope of the present SAR.	
Micah Runner – Black Hills Corporation – 1	
Answer	
Document Name	
Comment	

Black Hills Corporation (BHP) agrees with EEI's additional comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to Mark Gray of EEI.	
Darcy O'Connell - California ISO - 2	
Answer	
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the SDT's response to the IRC Standards Review Committee comments by Charles Yeung.	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no additional comments.	

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
You are welcome.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends using NERC Glossary terms where appropriate or defining terms that are not clearly defined in the NERC Glossary. For example, criteria numbers 8 and 9 under Requirement R1 use the term “highest operator established emergency	

transformer rating", and criterion number 9 also uses the term "maximum applicable nameplate rating". Neither of these terms exist in the NERC Glossary, though the terms Emergency Rating and Rating do exist in the NERC Glossary.

In Section C 1.2, Texas RE noticed the use of the term Data Retention. It appears that other proposed standards are using the term Evidence Retention as in proposed Reliability Standards CIP-012-2, VAR-002-5, MOD-026-2, IRO-010-5, and TOP-003-6.

Texas RE noticed that Section C 1.3 Compliance Monitoring and Enforcement Processes differs from Section C1.3 in other currently proposed standards, where it describes the Compliance Monitoring and Enforcement Program. Is this the SDT's intent?

Texas RE has the following comments on Attachment B:

- The first bullet in "Circuits to evaluate" needs a space between "200" and "kv"
- Criteria B1 does not mention the ERCOT Interconnection. Is this the SDT's intent?
- The footer page numbers need corrected ("Page 17 of 16")
- Since Criterion B3 is referring to NUC-001, is "Transmission Entity" referring to Transmission Entity as described in section A 4 of NUC-001-4?

In the Implementation Plan, under Time Period to Address New Designations, correct "pursyant" to "pursuant".

It is unclear what the "applicable effective date" is referencing since, presumably, a "New Designation" under PRC-023-6 would only occur after the effective date of PRC-023-6.

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. However, the SDT believes that your first comment is outside the scope of the SAR under which the SDT operates. The SDT believes that changes to the section C 1.2 are outside the scope of the present SAR. The SDT believes that changes to the section C 1.3 are outside the scope of the present SAR. The SDT response to your Attachment B comments are as follows: • We will correct the spacing referenced in your first bullet • The SDT believes that second bullet is outside the scope of the SAR. The absence of ERCOT from Criteria B1 appears to be a product of the original version of the Attachment B. • We will correct the footer page numbers referenced in your third bullet • “Transmission Entity” is defined for purpose of the NUC-001 standard and is not a defined NERC Glossary Term. However, the interpretation of “Transmission Entity” in Criteria B3 is outside the scope of this project SAR. The SDT will correct the spelling of “pursyant” in the final Implementation Plan. The SDT believes that a “New Designation” for an Element may occur anytime the Planning Coordinator performs their analysis under Criteria B4 using the specified one to five year planning horizon. The SDT is merely attempting to clarify when the Element must achieve compliance with the Standard after the Element has been identified by the Planning Coordinator.	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to Mark Gray of EEI.	
Daniel Gacek - Exelon – 1	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to Mark Gray of EEI.	
Kinte Whitehead - Exelon – 3	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to Mark Gray of EEI.	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI offers the following additional input for SDT consideration: Under Section B. (Associated Documents) the following document is Referenced: "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008." However, the hyperlink appears to be broken and the associated document has not been included in the documents to be reviewed by the industry, except for Appendix C. While Appendix C a portion of this document that is of greatest concern, the entire document should be revised, updated and attached for industry review. The Compliance Section of PRC-023-6 does not appear to conform to the latest approved language that is to be used in new or revised Reliability Standards. Please update this section to conform to the current Compliance language for NERC Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Use of a different browser may allow document access through the present link. The NERC System Protection and Control Work Group is the owner of this document. Revision is already in the SPCWG work plan for 2023. Industry will have the opportunity to review and comment on the results. The Compliance Section of the standard is outside the scope of the present SDT's SAR.	
Alison MacKellar - Constellation – 5	
Answer	
Document Name	

Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
You are welcome.	
Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	

Change Data Retention Section 1.2 to: The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 since the last audit period. Section D1.2 (Data Retention): In 1st paragraph, the sentence should end with a period instead of a semi-colon. Please consider updating section C. Compliance to use the most up-to-date version of the NERC wording for section C. Compliance. The wording used in Section C. Compliance, for draft 1 of PRC-023-6, is obsolete. Please consider adding the Planning Coordinator to the Applicable Entities list in the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The first proposed change to Data Retention Section 1.2 is outside the scope of this SDT's SAR. The SDT will conform the section to correct punctuation. The SDT believes that changes to section C 1.2 are outside the scope of the present SAR. The SDT has added the Planning Coordinator to the Applicable Entities in the Implementation Plan.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	

Document Name	
Comment	

SPP recommend that the drafting team revise the current/future comment form to reflect the appropriate standard version so, it aligns with documentation posted to the NERC page. For example, the one stop shop details for PRC-023-4 shows that this standard became effective on April 1, 2017 with an inactive date of March 31, 2024. However, PRC-023-5 will becomes effective April 1, 2024. Our interpretation is that all proposed changes would be associated with PRC-023-5 instead of PRC-023-4 in which the background information and the comment form suggests on the project page. Additionally, the redline document suggests that PRC-023-5 is the appropriated document to be mentioned in the background information. From our perspective, this creates confusion on which document is being used to support the drafting teams efforts.

Additionally, SPP recommends the drafting team further develop the physical document for the Technical Rationale associated with the PRC-023-6 Standard by including rationale for the legacy requirements. The link located in the “Associated Documents” sections of both PRC-023-5 (Project 2015-09) and PRC-023-6 (proposed) appears to not work properly to grant access to this data, which will create issues for industry. Moreover, there was a NERC project conducted to remove all Technical Rationale and Guidelines and Technical Basis from the back of all standards and put into structured independent formatted documentation. From our perspective, a link in the Associated Documents section of the standard in place of a separate Technical Rationale document doesn’t align with NERCs intent for drafting teams and their development of quality independent documentation. The proposed Technical Rationale document for PRC-023-6 should be updated to include the information that is associated with the link described above to be consistent with the current template for standards.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The draft PRC-023-6 that was posted for comment is based on the FERC approved PRC-023-5. The changes from PRC-023-4 to PRC-023-5 only affected Attachment B.

The Technical Rationale specifically supports the proposed revisions to the Standard. Development of a Technical Rationale for the entire standard is beyond the scope of this SDT SAR. The NERC System Protection and Control Work Group is already scheduled to consider revision of the "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008" including its Attachment C in their 2023 work plan.

Use of a different browser may allow document access through the present link.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	
Document Name	
Comment	
The IRC SRC supports improvements to clarify requirements on how Out-of-Step Blocking protection schemes should work. The proposed changes will provide more certainty in how these schemes will perform to reduce exposure to islanding. We do ask NERC to consider the implementation schedule and need for these changes in the context of the numerous other standards being developed and anticipated to be adopted. As described in the Technical Rationale, situations where OOSB relays may have not been correctly coordinated have seen little direct impact on system reliability. If this initial ballot fails and industry needs to expend more resources to review changes to reach consensus, we ask NERC to consider the immediacy of these changes relative to other risks where PRC requirements revisions are needed. Industry protection schemes expertise should be focused on the greatest reliability threats.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees that industry expertise should be focused on the greatest reliability threats. The proposed changes do not add new requirements. That said, the industry response to the SDT proposal has indicated substantial consensus to approve this proposal, so there seems to be no need for any further delay on this project.	

End of Report

Reminder

Standards Announcement

Project 2021-05 Modifications to PRC-023

Initial Ballots and Non-binding Poll Open through December 2, 2022

Now Available

The initial ballots and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels for Project 2021-05 Modifications to PRC-023 are open through **8 p.m. Eastern, Friday, December 2, 2022**.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.
For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-05 Modifications to PRC-023 observer list” in the Description Box.

404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2021-05 Modifications to PRC-023

Formal Comment Period Open through December 2, 2022
Ballot Pools Forming through November 15, 2022

Now Available

A formal comment period is open through **8 p.m. Eastern, Friday, December 2, 2022** for the following:

- PRC-023-6 – Transmission Relay Loadability
- PRC-023-6 Implementation Plan

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Tuesday, November 15, 2022.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Initial ballots for the standard and implementation plan, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 23 – December 2, 2022**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-05 Modifications to PRC-023” in the Description Box.

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/262)
Ballot Name: 2021-05 Modifications to PRC-023 PRC-023-6 IN 1 ST
Voting Start Date: 11/23/2022 12:01:00 AM
Voting End Date: 12/5/2022 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 221
Total Ballot Pool: 274
Quorum: 80.66
Quorum Established Date: 12/5/2022 1:04:14 PM
Weighted Segment Value: 98.37

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	56	0.982	1	0.018	0	5	13
Segment: 2	6	0.3	3	0.3	0	0	0	2	1
Segment: 3	66	1	50	0.98	1	0.02	0	5	10
Segment: 4	10	0.6	6	0.6	0	0	0	0	4
Segment: 5	65	1	44	0.978	1	0.022	0	4	16
Segment: 6	46	1	34	0.971	1	0.029	0	2	9
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	274	5.4	198	5.312	4	0.088	0	19	53

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Alain Mukama		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	John Daho	None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Santee Cooper	Chris Wagner		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Affirmative	N/A
1	Western Area Power Administration	Sean Erickson		None	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Andrew Gallo		Abstain	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		None	N/A
2	ISO New England, Inc.	John Pearson	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	AEP	Kent Feliks		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Maria Pardo		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		None	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Northern California Power Agency	Marty Hostler	James Mearns	None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	None	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Pattern Operators LP	George E Brown		None	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Abstain	N/A
5	Sacramento Municipal Utility District	Pedro Juarez	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

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Showing 1 to 274 of 274 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/262)
Ballot Name: 2021-05 Modifications to PRC-023 PRC-023-6 | Implementation Plan IN 1 OT
Voting Start Date: 11/23/2022 12:01:00 AM
Voting End Date: 12/5/2022 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 220
Total Ballot Pool: 273
Quorum: 80.59
Quorum Established Date: 12/5/2022 1:04:26 PM
Weighted Segment Value: 100

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	56	1	0	0	0	6	13
Segment: 2	6	0.3	3	0.3	0	0	0	2	1
Segment: 3	65	1	48	1	0	0	0	7	10
Segment: 4	10	0.6	6	0.6	0	0	0	0	4
Segment: 5	65	1	44	1	0	0	0	5	16
Segment: 6	46	1	34	1	0	0	0	3	9
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.3	3	0.3	0	0	0	2	0
Totals:	273	5.3	195	5.3	0	0	0	25	53

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Alain Mukama		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	John Daho	None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Affirmative	N/A
1	Western Area Power Administration	Sean Erickson		None	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Andrew Gallo		Abstain	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		None	N/A
2	ISO New England, Inc.	John Pearson	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Maria Pardo		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		None	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	None	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	None	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Pattern Operators LP	George E Brown		None	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Abstain	N/A
5	Sacramento Municipal Utility District	Pedro Juarez	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

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BALLOT RESULTS

Ballot Name: 2021-05 Modifications to PRC-023 PRC-023-6 | Non-binding Poll IN 1 NB
Voting Start Date: 11/23/2022 12:01:00 AM
Voting End Date: 12/5/2022 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 204
Total Ballot Pool: 260
Quorum: 78.46
Quorum Established Date: 12/5/2022 2:45:52 PM
Weighted Segment Value: 99.36

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	72	1	47	1	0	0	11	14
Segment: 2	5	0.2	2	0.2	0	0	2	1
Segment: 3	61	1	37	1	0	0	14	10
Segment: 4	10	0.6	6	0.6	0	0	0	4
Segment: 5	62	1	35	0.972	1	0.028	9	17
Segment: 6	44	1	25	1	0	0	9	10
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	5	0.3	3	0.3	0	0	2	0
Totals:	260	5.2	156	5.172	1	0.028	47	56

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Alain Mukama		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	MEAG Power	David Weekley	John Daho	None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Affirmative	N/A
1	Western Area Power Administration	Sean Erickson		None	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	Electric Reliability Council of Texas, Inc.	Andrew Gallo		Abstain	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		None	N/A
2	ISO New England, Inc.	John Pearson	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	William Berry		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Maria Pardo		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		None	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	None	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	None	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Pattern Operators LP	George E Brown		None	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Abstain	N/A
5	Sacramento Municipal Utility District	Pedro Juarez	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	Western Area Power Administration	Chrystal Dean		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

Previous 1 Next

Showing 1 to 260 of 260 entries

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

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/29/2021 – 07/28/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	10/03/2022 – 11/17/2022
45-day formal or informal comment period with additional ballot	12/05/2022 – 01/18/2023
10-day final ballot	01/10/2023 – 01/19/2023
Board adoption	02/15/2023

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:** **Transmission Relay Loadability**
2. **Number:** PRC-023-6
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi- directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV

that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
    - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
    - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
    - 115% of the highest emergency rating of the series capacitor.
    - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Reserved.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

R2. Reserved.

M2. Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the

ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

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.

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record 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	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	**Reserved.**
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners,	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)	Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

D. Regional Variances

None.

E. Associated Documents

The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

NERC Reliability Standard PRC-023-6 Implementation Plan.

NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
6	March 4, 2022	FERC Order issued approving PRC-023-5	

Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current- based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Reserved.

2.4. Reserved.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

- **a.** Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
- **b.** For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
- **c.** When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
- **d.** The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.
  - **i.** If the Facility Rating is based on a loading duration of up to and including four

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

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Description of Current Draft

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/29/2021 – 07/28/2021

Anticipated Actions	Date
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Board adoption	02/15/2023

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Term(s):
None.

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-6
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi- directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV

that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
    - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
    - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
    - 115% of the highest emergency rating of the series capacitor.
    - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. ~~Not used~~ Reserved.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

R2. Reserved.

M2. Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the

ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

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.

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record 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	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	**Reserved.**
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners,	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)	Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

D. Regional Variances

None.

E. Associated Documents

The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

NERC Reliability Standard PRC-023-6 Implementation Plan.

NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
6	March 4, 2022	FERC Order issued approving PRC-023-5	

Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
   - **1.1.** Phase distance.
   - **1.2.** Out-of-step tripping.
   - **1.3.** Switch-on-to-fault.
   - **1.4.** Overcurrent relays.
   - **1.5.** Communications aided protection schemes including but not limited to:
     - **1.5.1** Permissive overreach transfer trip (POTT).
     - **1.5.2** Permissive under-reach transfer trip (PUTT).
     - **1.5.3** Directional comparison blocking (DCB).
     - **1.5.4** Directional comparison unblocking (DCUB).
   - **1.6.** Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current- based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
   - **2.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
     - Overcurrent elements that are only enabled during loss of potential conditions.
     - Elements that are only enabled during a loss of communications except as noted in section 1.6.
   - **2.2.** Protection systems intended for the detection of ground fault conditions.
   - **2.3.** Reserved.
   - **2.4.** Reserved
   - **2.5.** Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
   - **2.6.** Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
   - **2.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
   - **2.8.** Relay elements associated with dc lines.
   - **2.9.** Relay elements associated with dc converter transformers.

Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria
If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

- **a.** Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
- **b.** For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
- **c.** When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
- **d.** The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.
  - **i.** If the Facility Rating is based on a loading duration of up to and including four

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

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

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/29/2021 – 07/28/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	10/03/2022 – 11/17/2022
45-day formal or informal comment period with additional ballot	12/05/2022 – 01/18/2023
10-day final ballot	01/10/2023 – 01/19/2023
Board adoption	02/15/2023

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:** **Transmission Relay Loadability**

2. **Number:** PRC-023-~~5~~6

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   4.1. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi- directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV

that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. ~~Not used~~ Reserved.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

  10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

R2. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*~~ Reserved.

M2. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)~~ Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-~~5~~6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~5~~6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-~~5~~6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

~~C. Measures~~

~~**M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per Standard PRC-023-5 — Transmission Relay Loadability Page 5 of 16~~

~~criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)~~

~~**M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)~~

~~**M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)~~

~~**M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)~~

~~**M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)~~

M6. ~~Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-5, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)~~

C. ~~D.~~ 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. ~~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 ~~Data~~ 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.

~~The Transmission Owner, Generator Owner, Distribution Provider and Planning 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, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and ~~Assessment Processes~~ 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.

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Violation Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

~~1.4. Additional Compliance Information~~

~~None.~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	Reserved. ~~**The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.**~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit. OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(part 6.2)		the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

D. ~~E.~~ Regional Variances ~~Diferences~~

None.

E. ~~F.~~ Associated ~~Supplemental Technical Reference~~ Documents

The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:
http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

NERC Reliability Standard PRC-023-6 Implementation Plan.

NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
6	March 4, 2022	FERC Order issued approving PRC-023-5	

~~PRC-023-5 —~~ Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
   - **1.1.** Phase distance.
   - **1.2.** Out-of-step tripping.
   - **1.3.** Switch-on-to-fault.
   - **1.4.** Overcurrent relays.
   - **1.5.** Communications aided protection schemes including but not limited to:
     - **1.5.1** Permissive overreach transfer trip (POTT).
     - **1.5.2** Permissive under-reach transfer trip (PUTT).
     - **1.5.3** Directional comparison blocking (DCB).
     - **1.5.4** Directional comparison unblocking (DCUB).
   - **1.6.** Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current- based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
   - **2.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
     - Overcurrent elements that are only enabled during loss of potential conditions.
     - Elements that are only enabled during a loss of communications except as noted in section 1.6.
   - **2.2.** Protection systems intended for the detection of ground fault conditions.
   - **2.3.** Reserved. ~~Protection systems intended for protection during stable power swings.~~
   - **2.4.** Reserved. ~~Not used.~~
   - **2.5.** Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
   - **2.6.** Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
   - **2.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
   - **2.8.** Relay elements associated with dc lines.
   - **2.9.** Relay elements associated with dc converter transformers.

~~PRC-023-5 —~~ Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

- **a.** Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
- **b.** For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
- **c.** When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
- **d.** The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-5
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

6. Not used.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
    - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
    - 115% of the highest operator established emergency transformer rating.

    10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
    - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
    - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
    a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
    b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-5, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-5 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-5, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-5, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. 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 Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning 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, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

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

1.4. Additional Compliance Information

None.

Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

   "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	

PRC-023-5 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-5 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Implementation Plan

Project 2021-05 Modifications to PRC-023
Reliability Standard PRC-023-6

Applicable Standard(s)

- PRC-023-6 –Transmission Relay Loadability

Requested Retirement(s)

- PRC-023-5 – Transmission Relay Loadability

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider
- Planning Coordinator

General Considerations

None.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) 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 (ii) the effective date of Reliability Standard PRC-023-5.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) 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 (ii) the effective date of Reliability Standard PRC-023-5.

Retirement Date

The version of Reliability Standard PRC-023 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-023-6.

Initial Performance Date

Each Planning Coordinator shall conduct its first assessment under Reliability Standard PRC-023-6 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-4 or PRC-023-5, whichever occurs first.

Time Period to Address New Designations

Each Transmission Owner, Generator Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2021-05 Modifications to PRC-023
Reliability Standard PRC-023-6

Applicable Standard(s)

- PRC-023-6 –Transmission Relay Loadability

Requested Retirement(s)

- PRC-023-5 – Transmission Relay Loadability

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider
- Planning Coordinator

General Considerations

None.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) the first day of the first calendar 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 (ii) the effective date of Reliability Standard PRC-023-5.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) 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 (ii) the effective date of Reliability Standard PRC-023-5.

Retirement Date

The version of Reliability Standard PRC-023 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-023-6.

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Initial Performance Date

Each Planning Coordinator shall conduct its first assessment under Reliability Standard PRC-023-6 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-4 or PRC-023-5, whichever occurs first.

Time Period to Address New Designations

Each Transmission Owner, Generator Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

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Technical Rationale for Reliability Standard PRC-023-6

January 2023

PRC-023-6 – Transmission Relay Loadability

Rationale for Applicability Section

No changes are proposed to the Applicability of Reliability Standard PRC-023-6 from the prior version.

Rationale for Retirement of Requirement R2

The most significant rationale to retire Requirement R2 is that the single fault condition regulated by Requirement R2 is a subset of the faults regulated by R1 and requires the same entity response. R2 adds nothing to the "… all fault conditions" of R1, so a failure to comply with R2 would also mean failure to comply with R1. Therefore retirement of R2 does not create a reliability gap.

The Standard Drafting Team recommends the retirement of PRC-023-5, Requirement R2.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.

The Standard Drafting Team also recommends the retirement of Attachment A, Item 2.3 exclusion:

2.3 Protection systems intended for protection during stable power swings [excluded].

Summary of Justification to Retire Requirement R2

- The fault condition regulated by Requirement R2 is also regulated by Requirement R1 and requires the same entity response.
- A significant error in the "Determination and Application of Practical Relaying Loadability Ratings," Appendix C, January 9, 2007 documentation of power swing blocking capabilities appears to have led to development of Requirement R2.
- The development history of Requirement R2 used an incomplete discussion of power swings that appears to have convinced FERC to direct a separate requirement on the subject, rather than accept alternate technical solutions that would assure detection and clearing of faults that may occur during power swings.
- The primary intent of this standard is to address a security aspect of the protection system. Adding a dependability focused requirement in this standard results in confusion in setting the protective relays.

- The roughly 10 years of experience under Requirement R2 has shown that neither compliance, system operations, nor system disturbances have had any significant impact on system reliability. In addition, whatever the original risk addressed by Requirement R2, that is now reduced due to subsequent Protection System upgrades.

I. Requirement R2 is Effectively Redundant to the Performance Required by R1 of PRC-023-5

R1 includes the phrase "… prevent its phase protective relay settings from limiting transmission system loadability *while maintaining reliable protection of the BES* ***for all fault conditions***." (emphasis added).

Requirement R2 singles out a specific fault condition when it specifies that the applicable entity "shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1." This is not an expansion of the "… all fault conditions" identified in R1. So if an entity failed to comply with R2, they would also fail to comply with R1.

II. Power Swing Blocking, Appendix C Error

NERC System Protection and Control Task Force (SPCTF) wrote the initial version of PRC-023 Reference Determination and Application of Practical Relaying Loadability Ratings, 8/14/2006. This document was revised on January 9, 2007 and added Appendix C to discuss out of step blocking. This discussion only referenced the type of schemes that are typically implemented using electromechanical relays. The conclusion was that "if (and as long as) a system load condition operates the out-of-step blocking relay, the distance relay will be prevented from operating for a subsequent fault condition! A timer can be added such that the relay issues a trip if the out of step timer does not reset within a defined time." Subsequent versions of this document (2017 is the latest) have not changed this wording. These two sentences appear to be the origin of the item that addressed out of step blocking in PRC-023-1 Attachment A.

The above quoted "… subsequent fault condition!" statement remains true for traditional electromechanical relay schemes. The subsequent (and last) sentence indicates that the (optional?) timer would be used to trip the element. This is not appropriate because tripping should not occur during the identified heavy load conditions unless a fault actually occurs on the element. A timer is not capable of such fault detection.

Appendix C does not discuss why the "… subsequent fault condition!" that became Requirement R2 should be excluded from "… all fault conditions" that remains part of Requirement R1. Given the context of Appendix C, the appropriate conclusion would seem to be that unmodified traditional electromechanical PSB schemes, depending on their settings, may not be able to comply with the R1 or R2 requirements. Unfortunately, the lack of discussion of either "… all fault conditions" or more advanced PSB schemes leaves the impression that there is no acceptable technical solution to this issue.

The present SDT recommends that SPCWG review and update this document and has proposed several edits and additions, including several methods available to protection engineers to remediate the fault identification issues during PSB that were identified by the original drafting team. Some combination of these methods to PSB schemes answers the technical concern to allow tripping for any fault that occurs during a heavy loading condition that results in PSB operation. In combination with the existing wording in R1, this makes the existing R2 redundant and therefore unnecessary.

Therefore the present SDT asserts that no specific reference to power swing blocking is necessary as a PRC-023 requirement, but can be appropriately acknowledged in this Technical Rationale~~,~~ and in a revision to "Determination and Application of Practical Relaying Loadability Ratings," Appendix C.

III. Development History of Requirement R2

The original August 2006 version of PRC-023 Reference Determination and Application of Practical Relaying Loadability Ratings described the standard's objective with respect to faults:

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The introduction also included item "1.3 Out-of-Step blocking," but with no further discussion.

The original wording in PRC-023-1, Attachment A regarding power swing blocking was:

This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

At least one commenter was concerned that this original wording from the PRC-023-1 SDT did not recognize that the PSB can be reset to allow detection of faults after the PSB function asserts. However, the SDT thought no change was necessary. This SDT response does not acknowledge that resetting of the PSB function is even possible.

- **Comment:** Attachment A 2. A word PERMANENTLY should be added before "block trip…"?[1]
    - **Response:** Attachment A 2- Most commenters seemed to understand the intent of this item without further clarification. If an out[-]of-step relay asserts on load and blocks the trip of fault protective relays, and a fault occurs during that loading condition, the out-of-step relay will prevent successful operation of the fault protective relay. (3/9/2007)

[1] Microsoft Word - Consider_Comments_D2_Relay_Loadability_09Mar07.doc (nerc.com), DRAFT 2 comments, pp 41-43

Another commenter expressed a related concern for remotely-connected systems. The SDT acknowledged that some scheme modification may be needed but did not describe what a "more complex" scheme would do.

- **Comment:** I am concerned that this standard as drafted would limit the application of out of step block trip functions for remotely-connected systems.[2]
    - **Response:** Attachment A, Item 2 is intended to ensure that facilities are adequately protected for faults. Out-of-step blocking elements may prevent tripping for true faults during extreme loading conditions. For conditions involving remotely-connected systems, more complex out-of-step blocking schemes may be needed. (1/31/2008)

When FERC reviewed (and eventually approved) the proposed PRC-023-1, an objection was that referencing out of step blocking in Appendix A as a "shall" item was important, but not enforceable because it was not a requirement and had no VSL or VRF. FERC observed the use of this "shall" language and directed that this item be rewritten as a requirement. FERC ordered: (Order 733, paragraph 244)

We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.

The standard drafting team for PRC-023-2 then proposed to add wording to Requirement R1:

". . . and to prevent its out-of-step blocking schemes from blocking tripping for fault conditions."

One commenter[3] at the time addressed some technical aspects of this specific wording, in part:

The specific wording proposed by the Drafting Team may prevent using the out-of-step-block functions of many modern and widely used line protection relays (e.g. SEL-321 and later models and GE-UR). These relay's OSB function first blocks the protection elements from tripping, then uses a short delay and/or other information to determine whether the observed and perhaps evolving condition really represents a fault, in which case the blocking is reset to allow tripping. Such a block/reset operation is the most common technology available and would appear to lie within the intent of FERC in [Order 733] paragraph 244, but could be excluded by the presently proposed language.

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2 https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_Initial_Ballot_PRC-023_Relay_Loadability_31Jan08.doc DRAFT 4 Comments, p 16

3 https://elibrary.ferc.gov/eLibrary/filedownload?fileid=018154B3-66E2-5005-8110-C31FAFC91712 pp 169-170

Another commenter added[4]:

We suggest that the added phrase be removed from R1 and a new requirement created. Suggested wording is "Protection Systems that block for stable swings or out-of-step conditions shall be evaluated to ensure that appropriate tripping will occur for in-section faults that occur during the condition. Some additional delay may be required and is acceptable to ensure that the appropriate tripping occurs."

The SDT's conclusion was:

The SDT agrees and removed out-of-step blocking from Requirement R1. The requirement pertaining to evaluation of out-of-step blocking protection has been moved to a separate requirement (now Requirement R2) to more clearly delineate this requirement from assessment of relay loadability of phase protective relays.

Both of these commenters suggested what became R2 but did not question whether "… all fault conditions" in R1 already included the faults intended to be detected by R2. It appears that, although NERC is permitted to propose an equally efficient and effective alternative to address a FERC directive, the SDT did not consider any alternate solution to FERC's Order 733 directive to include a separate requirement to detect PSB-related faults.

The SDT's proposed (and eventually approved) Violation Severity Level (VSL) and Violation Risk Factor (VRF) for both PRC-023-2 Requirements R1 and R2 were the same.

This SDT realizes that the meaning of original language in the Attachment A was inverted as it was converted to Requirement R2. The wording was changed from "…shall be evaluated to ensure that they do not block trip …" to "… shall set its out-of-step blocking elements to allow tripping …". This resulted in a significant change in how the Requirement R2 is interpreted by protection engineers. The revised emphasis is on relay settings, rather than evaluation of the PSB scheme itself. The focus shifted from evaluating the PSB scheme to the PSB elements, primarily blinders, which are directly controlled by the settings. In cases of conflict, the remedy was to either not use the PSB scheme or significantly increase the scheme complexity.

At least one entity disabled at least two power swing blocking schemes

- Due to concern whether use of a reset timer would achieve the spirit of Requirement R2 to clear faults within appropriate time.
- The outer PSB characteristic could not be set within the loadability characteristics.

[4] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=018154B3-66E2-5005-8110-C31FAFC91712 p 189

IV. Security versus Dependability[5]

The Purpose of PRC-023 is:

Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

The emphasis of PRC-023 is on the security of the transmission system to avoid unnecessary trips during heavy load conditions when no fault occurs. The Purpose and Requirement R1 does include language that "… all fault conditions" (dependability) must be recognized. Requirement R2 carves out a separate dependability item "… to allow tripping of phase protective relays for faults that occur during the loading conditions" as in R1.

The dependability language in R1 is an appropriate balancing of the intent of R1 (security), so mentioning dependability in R1 does not cause confusion. Retiring R2 will make the standard more focused and clear.

V. Experience with Requirement R2 functionality

Experience is not a perfect guide to judging the necessity of Requirement R2. Absence of evidence is not evidence of absence of failure to clear faults during PSB operations. The approximately 10 years of available history since R2 has been enforceable does provide useful background to judge the scale of potential risk to the bulk power system following R2 retirement. No statistical analysis or antidotal examples can prove that faults will never occur while a relay has asserted its PSB function. However, the extremely small historical occurrence of events that may qualify as faults during a power swing, perhaps as low as zero in this summary, does significantly limit the risk to the bulk power system.

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A review of compliance violations of the existing Requirement R2 showed only two violations, both discovered about one year after the requirement became enforceable. Both were discovered through review of documentation of relay settings, not from system operations. In both cases the associated Risk Description indicated that the issues posed minimal risk to the reliability of the bulk power system.

An audit finding was due to a 12% deviation from the required loadability and only affected one of the two redundant protection systems. The entity re-calculated their relay settings and found no other related issues on their system.

[5] For the purpose of this discussion the IEEE Standard Dictionary of Electrical and Electronics Terms defines dependability (relay or relay systems) as the facet of reliability that relates to the degree of certainty that a relay or relay system will operate correctly. Similarly, security (relay or relay systems) is the facet of reliability that relates to the degree of certainty that a relay or relay system will not operate incorrectly. Finally, reliability (relay or relay systems) is a measure of the degree of certainty that a relay or relay system will perform correctly. NOTE: Reliability denotes certainty of correct operation together with assurance against incorrect operation from all extraneous causes.

A self-report identified that one of three redundant protection schemes on each of three transmission lines was impacted by an OSB calculation error. Relay settings on the other two protection schemes for each transmission line were not impacted and acceptable fault clearing would have occurred even if the loading conditions specified in PRC-023-2 R1 were to occur simultaneously with a three-phase fault on the line.

It does not appear that any risk was imposed to the Bulk Power System from these violations, or even whether failure of one of two or three redundant relays to trip for a fault would have constituted a Misoperation since the Composite Protection System would have operated correctly.

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Several event reports cover system performance during cold weather events, hurricanes, and other major weather conditions. Most system impacts resulted from physical damage. None of these reports identified any system impacts due to faults during power swings or power swing blocking. Protection System impacts from all of these events ranged from very minor to none.

- **Cold Weather Training Materials**
    - This is guidance material for preparation and response rather than an event description.
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- **FRCC System Disturbance**

  - The FRCC disturbance of February 26, 2008 included a zone 1 trip during a power swing (PSB was not applied) but was roughly the 15th event in the disturbance sequence. The report did not recommend any related protection system changes.

- **August 2003 Northeast Blackout Event**

  - The Northeast blackout of August 14, 2003 did involve a few out of step line trips on distance relay elements late in the event sequence that may have been prevented by application of PSB. However, the entire event did not include any case of failure to clear a fault due to PSB relay elements failing to reset under relay loadability conditions described in PRC-023.

Protection System Improvements

Most entities have continued to replace electromechanical, solid state, and early generations of microprocessor relays with newer microprocessor relays since Requirement R2 became effective. The effect of these upgrades is that these newer relays can more easily comply with the intent of the original wording in Appendix A of PRC-023-1. This upgrade process further reduces any risk that is intended to be addressed by Requirement R2. For example, one entity that extensively applies PSB and out of step tripping on its transmission system began 2011 with 161 of 471 (34%) of affected line terminals protected by these lower capability (electromechanical) relays. By 2022 only 19 of 699 (2.7%) of the affected line terminals were still protected by these less capable relays. A second entity has upgraded all of their out of step applications to modern microprocessor-based schemes. A third entity has upgraded all of its out of step applications above 200 kV to modern microprocessor relays and has only a single electromechanical application still in service at 115 kV.

Justification to Retire Attachment A, Item 2.3 Exclusion

Attachment A item 2.3 excludes “Protection systems intended for protection during stable power swings”. This exclusion is referencing “Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations”[6]. Florida was cited in the record of development as an example of where these schemes were employed. Research has indicated that these schemes no longer exist and there is no need for a power swing tripping exclusion. PRC-026 covers stable power swings adequately. Since Item 2.3 is an exclusion, there is no overlap with PRC-026.

The original PRC-023-1 SDT response to comments included the following statements:

- (12) In some parts of North America (for example Florida), there are relay systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other to maintain desirable performance …. [footnote 6, p 48]
- Where out of step tripping or blocking relays are applied independently within the system they must comply with the standard. [footnote 6, p 55]

The normal practice for power systems generally should not be to intentionally separate during stable power swings. It is the understanding of the present Standard Drafting Team that the example scheme from Florida is no longer used. The second bullet response seems to say that exclusion 2.3 should never have been included.

The present Standard Drafting Team asserts that Attachment A, Item 2.3 can be safely retired without creating a reliability gap.

[6] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

Technical Rationale for Reliability Standard PRC-023-6

December 2022

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PRC-023-6 – Transmission Relay Loadability

Rationale for Applicability Section

No changes are proposed to the Applicability of Reliability Standard PRC-023-6 from the prior version.

Rationale for Retirement of Requirement R2

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The most significant rationale to retire Requirement R2 is that the single fault condition regulated by Requirement R2 is a subset of the faults regulated by R1 and requires the same entity response. R2 adds nothing to the "… all fault conditions" of R1, so a failure to comply with R2 would also mean failure to comply with R1. Therefore retirement of R2 does not create a reliability gap.

The Standard Drafting Team recommends the retirement of PRC-023-5, Requirement R2.

> R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.

The Standard Drafting Team also recommends the retirement of Attachment A, Item 2.3 exclusion:

> 2.3 Protection systems intended for protection during stable power swings [excluded].

SUMMARY OF JUSTIFICATION TO RETIRE REQUIREMENT R2

- The fault condition regulated by Requirement R2 is also regulated by Requirement R1 and requires the same entity response.
- A significant error in the "Determination and Application of Practical Relaying Loadability Ratings," Appendix C, January 9, 2007 documentation of power swing blocking capabilities appears to have led to development of Requirement R2.
- The development history of Requirement R2 used an incomplete discussion of power swings that appears to have convinced FERC to direct a separate requirement on the subject, rather than accept alternate technical solutions that would assure detection and clearing of faults that may occur during power swings.
- The primary intent of this standard is to address a security aspect of the protection system. Adding a dependability focused requirement in this standard results in confusion in setting the protective relays.
- The roughly 10 years of experience under Requirement R2 has shown that neither compliance, system operations, nor system disturbances have had any significant impact on system reliability. In addition,

whatever the original risk addressed by Requirement R2, that is now reduced due to subsequent Protection System upgrades.

I. Requirement R2 is Effectively Redundant to the Performance Required by R1 of PRC-023-5

R1 includes the phrase "… prevent its phase protective relay settings from limiting transmission system loadability *while maintaining reliable protection of the BES* ***for all fault conditions***." (emphasis added).

Requirement R2 singles out a specific fault condition when it specifies that the applicable entity "shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1." This is not an expansion of the "… all fault conditions" identified in R1. So if an entity failed to comply with R2, they would also fail to comply with R1.

II. Power Swing Blocking, Appendix C Error

NERC System Protection and Control Task Force (SPCTF) wrote the initial version of PRC-023 Reference Determination and Application of Practical Relaying Loadability Ratings, 8/14/2006. This document was revised on January 9, 2007 and added Appendix C to discuss out of step blocking. This discussion only referenced the type of schemes that are typically implemented using electromechanical relays. The conclusion was that "if (and as long as) a system load condition operates the out-of-step blocking relay, the distance relay will be prevented from operating for a subsequent fault condition! A timer can be added such that the relay issues a trip if the out of step timer does not reset within a defined time." Subsequent versions of this document (2017 is the latest) have not changed this wording. These two sentences appear to be the origin of the item that addressed out of step blocking in PRC-023-1 Attachment A.

The above quoted "… subsequent fault condition!" statement remains true for traditional electromechanical relay schemes. The subsequent (and last) sentence indicates that the (optional?) timer would be used to trip the element. This is not appropriate because tripping should not occur during the identified heavy load conditions unless a fault actually occurs on the element. A timer is not capable of such fault detection.

Appendix C does not discuss why the "… subsequent fault condition!" that became Requirement R2 should be excluded from "… all fault conditions" that remains part of Requirement R1. Given the context of Appendix C, the appropriate conclusion would seem to be that unmodified traditional electromechanical PSB schemes, depending on their settings, may not be able to comply with the R1 or R2 requirements. Unfortunately, the lack of discussion of either "… all fault conditions" or more advanced PSB schemes leaves the impression that there is no acceptable technical solution to this issue.

The present SDT recommends that SPCWG review and update this document and has proposed several edits and additions, including several methods available to protection engineers to remediate the fault identification issues during PSB that were identified by the original drafting team. Some combination of these methods to PSB schemes answers the technical concern to allow tripping for any fault that occurs

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during a heavy loading condition that results in PSB operation. In combination with the existing wording in R1, this makes the existing R2 redundant and therefore unnecessary.

Therefore the present SDT asserts that no specific reference to power swing blocking is necessary as a PRC-023 requirement, but can be appropriately acknowledged in this Technical Rationale~~,~~ and in a revision to “Determination and Application of Practical Relaying Loadability Ratings,” Appendix C.

III. Development History of Requirement R2

The original August 2006 version of PRC-023 Reference Determination and Application of Practical Relaying Loadability Ratings described the standard’s objective with respect to faults:

> While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The introduction also included item “1.3 Out-of-Step blocking,” but with no further discussion.

The original wording in PRC-023-1, Attachment A regarding power swing blocking was:

> This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

At least one commenter was concerned that this original wording from the PRC-023-1 SDT did not recognize that the PSB can be reset to allow detection of faults after the PSB function asserts. However, the SDT thought no change was necessary. This SDT response does not acknowledge that resetting of the PSB function is even possible.

- **Comment:** Attachment A 2. A word PERMANENTLY should be added before “block trip…”?[1]
  - **Response:** Attachment A 2- Most commenters seemed to understand the intent of this item without further clarification. If an out[-]of-step relay asserts on load and blocks the trip of fault protective relays, and a fault occurs during that loading condition, the out-of-step relay will prevent successful operation of the fault protective relay. (3/9/2007)

Another commentor expressed a related concern for remotely-connected systems. The SDT acknowledged that some scheme modification may be needed but did not describe what a “more complex” scheme would do.

- **Comment:** I am concerned that this standard as drafted would limit the application of out of step block trip functions for remotely-connected systems.[2]
  - **Response:** Attachment A, Item 2 is intended to ensure that facilities are adequately protected for faults. Out-of-step blocking elements may prevent tripping for true faults during extreme

[1] Microsoft Word - Consider_Comments_D2_Relay_Loadability_09Mar07.doc (nerc.com), DRAFT 2 comments, pp 41-43

[2] https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_Initial_Ballot_PRC-023_Relay_Loadability_31Jan08.doc DRAFT 4 Comments, p 16

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> loading conditions. For conditions involving remotely-connected systems, more complex out-of-step blocking schemes may be needed. (1/31/2008)

When FERC reviewed (and eventually approved) the proposed PRC-023-1, an objection was that referencing out of step blocking in Appendix A as a "shall" item was important, but not enforceable because it was not a requirement and had no VSL or VRF. FERC observed the use of this "shall" language and directed that this item be rewritten as a requirement. FERC ordered: (Order 733, paragraph 244)

> We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.

The standard drafting team for PRC-023-2 then proposed to add wording to Requirement R1:

> ". . . and to prevent its out-of-step blocking schemes from blocking tripping for fault conditions."

One commenter[3] at the time addressed some technical aspects of this specific wording, in part:

> The specific wording proposed by the Drafting Team may prevent using the out-of-step-block functions of many modern and widely used line protection relays (e.g. SEL-321 and later models and GE-UR). These relay's OSB function first blocks the protection elements from tripping, then uses a short delay and/or other information to determine whether the observed and perhaps evolving condition really represents a fault, in which case the blocking is reset to allow tripping. Such a block/reset operation is the most common technology available and would appear to lie within the intent of FERC in [Order 733] paragraph 244, but could be excluded by the presently proposed language.

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> We suggest that the added phrase be removed from R1 and a new requirement created. Suggested wording is "Protection Systems that block for stable swings or out-of-step conditions shall be evaluated to ensure that appropriate tripping will occur for in-section faults that occur during the condition. Some additional delay may be required and is acceptable to ensure that the appropriate tripping occurs."

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Both of these commenters suggested what became R2 but did not question whether "… all fault conditions" in R1 already included the faults intended to be detected by R2. It appears that, although

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- The FRCC disturbance of February 26, 2008 included a zone 1 trip during a power swing (PSB was not applied) but was roughly the 15^{th} event in the disturbance sequence. The report did not recommend any related protection system changes.

August 2003 Northeast Blackout Event

- The Northeast blackout of August 14, 2003 did involve a few out of step line trips on distance relay elements late in the event sequence that may have been prevented by application of PSB. However, the entire event did not include any case of failure to clear a fault due to PSB relay elements failing to reset under relay loadability conditions described in PRC-023.

Protection System Improvements

Most entities have continued to replace electromechanical, solid state, and early generations of microprocessor relays with newer microprocessor relays since Requirement R2 became effective. The effect of these upgrades is that these newer relays can more easily comply with the intent of the original wording in Appendix A of PRC-023-1. This upgrade process further reduces any risk that is intended to be addressed by Requirement R2. For example, one entity that extensively applies PSB and out of step tripping on its transmission system began 2011 with 161 of 471 (34%) of affected line terminals protected by these lower capability (electromechanical) relays. By 2022 only 19 of 699 (2.7%) of the affected line terminals were still protected by these less capable relays. A second entity has upgraded all of their out of step applications to modern microprocessor-based schemes. A third entity has upgraded all of its out of step applications above 200 kV to modern microprocessor relays and has only a single electromechanical application still in service at 115 kV.

JUSTIFICATION TO RETIRE ATTACHMENT A, ITEM 2.3 EXCLUSION

Attachment A item 2.3 excludes “Protection systems intended for protection during stable power swings”. This exclusion is referencing “Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance

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relative to voltage, frequency, and power oscillations"[6]. Florida was cited in the record of development as an example of where these schemes were employed. Research has indicated that these schemes no longer exist and there is no need for a power swing tripping exclusion. PRC-026 covers stable power swings adequately. Since Item 2.3 is an exclusion, there is no overlap with PRC-026.

The original PRC-023-1 SDT response to comments included the following statements:

- (12) In some parts of North America (for example Florida), there are relay systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other to maintain desirable performance …. [footnote 6, p 48]
- Where out of step tripping or blocking relays are applied independently within the system they must comply with the standard. [footnote 6, p 55]

The normal practice for power systems generally should not be to intentionally separate during stable power swings. It is the understanding of the present Standard Drafting Team that the example scheme from Florida is no longer used. The second bullet response seems to say that exclusion 2.3 should never have been included.

The present Standard Drafting Team asserts that Attachment A, Item 2.3 can be safely retired without creating a reliability gap.

[6] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

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UPDATED

Standards Announcement

Project 2021-05 Modifications to PRC-023

Final Ballot Extended, Now Open through January 24, 2023

Now Available

Due to updated documents on the project page (to correct inadvertent errors in Requirement R1 and reflect the proposed changes to the currently approved standard language), and to ensure ample time for review, the final ballot for **Project 2021-05 Modifications to PRC-023** has been extended and is now open through **8 p.m. Eastern, Tuesday, January 24, 2023.**

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2021-05 Modifications to PRC-023

Final Ballot Open through January 19, 2023

Now Available

A final ballot for **Project 2021-05 Modifications to PRC-023** is open through **8 p.m. Eastern, Thursday, January 19, 2023.**

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

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Next Steps

The voting results will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

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Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2021-05 Modifications to PRC-023 PRC-023-6 FN 2 ST
Voting Start Date: 1/10/2023 12:01:00 AM
Voting End Date: 1/24/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 241
Total Ballot Pool: 274
Quorum: 87.96
Quorum Established Date: 1/10/2023 10:56:37 AM
Weighted Segment Value: 98.27

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	60	0.968	2	0.032	0	5	8
Segment: 2	6	0.3	3	0.3	0	0	0	2	1
Segment: 3	66	1	55	0.982	1	0.018	0	4	6
Segment: 4	10	0.8	8	0.8	0	0	0	2	0
Segment: 5	65	1	49	0.98	1	0.02	0	4	11
Segment: 6	46	1	36	0.973	1	0.027	0	2	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	274	5.6	216	5.503	5	0.097	0	20	33

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Alain Mukama		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	John Daho	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Affirmative	N/A
1	Western Area Power Administration	Sean Erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Abstain	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		None	N/A
2	ISO New England, Inc.	John Pearson	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Maria Pardo		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		None	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Abstain	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		Abstain	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2021-05 Modifications to PRC-023 PRC-023-6 | Implementation Plan FN 2 OT
Voting Start Date: 1/10/2023 12:01:00 AM
Voting End Date: 1/24/2023 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 240
Total Ballot Pool: 273
Quorum: 87.91
Quorum Established Date: 1/10/2023 10:56:51 AM
Weighted Segment Value: 100

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	61	1	0	0	0	6	8
Segment: 2	6	0.3	3	0.3	0	0	0	2	1
Segment: 3	65	1	53	1	0	0	0	6	6
Segment: 4	10	0.8	8	0.8	0	0	0	2	0
Segment: 5	65	1	49	1	0	0	0	5	11
Segment: 6	46	1	36	1	0	0	0	3	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	5	0.3	3	0.3	0	0	0	2	0
Totals:	273	5.5	214	5.5	0	0	0	26	33

BALLOT POOL MEMBERS

Show All entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Alain Mukama		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	John Daho	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Affirmative	N/A
1	Western Area Power Administration	Sean Erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Abstain	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		None	N/A
2	ISO New England, Inc.	John Pearson	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Maria Pardo		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		None	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Abstain	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		Abstain	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

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Exhibit G

Standard Drafting Team Roster, Project 2021-05 Modifications to PRC-023

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Drafting Team Roster

Project 2021-05 Modifications to PRC-023

	Name	Entity
Chair	Gene Henneberg	NV Energy
Vice Chair	Chris Koteles	ITC
Members	Manish Patel	Southern Company Services
	Kandas Graham	Xcel Energy
	Michael Thompson	SEL Engineering Services
	Ding Lin	Manitoba Hydro
	Rod Smith	Duke Energy
NERC Staff	Ben Wu – Senior Standards Developer	North American Electric Reliability Corporation
	Marisa Hecht – Legal	North American Electric Reliability Corporation
	Lauren Perotti – Legal	North American Electric Reliability Corporation