North American Electric Reliability Corporation

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED DISTURBANCE MONITORING RELIABILITY STANDARDS PRC-028-1 AND PRC-002-5

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standards PRC-002-5 – Disturbance Monitoring and Reporting Requirements and PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources. The proposed Reliability Standards[4] would advance the reliability of the Bulk-Power System by ensuring that adequate data from both synchronous generating resources and Inverter-Based Resources (or "IBRs") is available to facilitate the analysis of disturbances on the Bulk-Power System, and that adequate data is available from IBRs to evaluate ride-through performance during disturbances. Having such data is necessary for system engineers to better understand the root causes and effects of large system disturbances and take the appropriate actions to protect system reliability—particularly as the Bulk-Power System transitions from a resource

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[1] 16 U.S.C. § 824o.

[2] 18 C.F.R. § 39.5 (2024).

[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006) [hereinafter ERO Certification Order].

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

mix consisting primarily of large synchronous resources located near population centers to one that is increasingly reliant on relatively smaller IBRs that are more geographically dispersed.

The proposed Reliability Standards are an integral part of NERC's proposed framework to address IBR reliability issues in a comprehensive and holistic manner. The proposed Reliability Standards addressed in this filing are responsive to the Commission's directives in Order No. 901 directing NERC to submit new or revised standards addressing IBR disturbance monitoring by November 4, 2024.[5] As discussed in detail below, the proposed Reliability Standards are part of a set of standards that collectively respond to the Commission's directives for requirements addressing IBR ride-through settings, ride-through performance, data recording, and analysis and mitigation of unexpected IBR performance. This proposed framework consists of the following standards and definitions:

- Proposed definition of the term Inverter-Based Resource, for inclusion in the *Glossary of Terms used in NERC Reliability Standards* (*separately filed, concurrently with this petition*);[6]
- Proposed Reliability Standard PRC-028-1 – Disturbance Monitoring and Reporting Requirements for IBR, with comprehensive disturbance monitoring and reporting requirements for IBRs;
- Proposed Reliability Standard PRC-029-1 – Frequency and Voltage Ride-through Requirements for IBR, with capability and performance-based requirements for IBR Ride-through performance, and the proposed definition of Ride-through (*separately filed, concurrently with this petition*); and

[5] Order No. 901, *Reliability Standards to Address Inverter-Based Resources*, 185 FERC ¶ 61,042 at P 229 (2023) [hereinafter Order No. 901].

[6] The proposed definition for this term, which is used throughout the proposed Reliability Standards addressed in the filing, is as follows:

> **Inverter-Based Resource (IBR)**: A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

- Proposed Reliability Standard PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation, requiring analysis and mitigation of IBR performance issues (*separately filed, concurrently with this petition*).

Proposed Reliability Standard PRC-028-1 would provide the data used to assess IBR performance in accordance with proposed Reliability Standards PRC-029-1 and PRC-030-1. The proposed standards would ensure that actual data of IBR performance during disturbances can be leveraged by NERC drafting teams addressing issues related to IBR model quality and planning and operational studies. Additional work is underway to complete the development of proposed Reliability Standards responsive to the Commission's Order No. 901 directives related to these issues by their respective deadlines in 2025 and 2026, with an orderly implementation of all new and revised requirements by 2030.

NERC requests that the Commission approve the proposed Reliability Standards, provided in Exhibit A hereto, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests approval of: (1) the associated Implementation Plan (Exhibit B); the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standards (Exhibit F); and the retirement of currently effective Reliability Standard PRC-002-4.

As required by Section 39.5(a) of the Commission's regulations,[7] this petition presents the technical basis and purpose of the proposed Reliability Standards, a summary of the development history, including the adoption of the proposed Reliability Standards by the NERC Board of Trustees on October 8, 2024 (Exhibit G), and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[8] (Exhibit C).

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[7] 18 C.F.R. § 39.5(a).

[8] *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 PP 262, 321-37 (2006) [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC 61,328 (2006).

I. SUMMARY

When disturbances happen on the Bulk-Power System, system engineers rely on disturbance monitoring data to understand the root causes and effects of the disturbance and to take actions that will protect system reliability in the future. When disturbance monitoring data is incomplete or insufficient, the resulting analysis and follow-up actions may be inaccurate or inadequate. For these reasons, the PRC-002 Reliability Standard has long required entities to maintain disturbance monitoring data recording capabilities to ensure sufficient disturbance monitoring data is available for analysis.

The PRC-002 standard was originally written with a focus on systems dominated by synchronous resources. This focus was appropriate, as it reflected the resource mix at the time. The Bulk-Power System, however, has undergone a rapid transformation in recent years, with IBRs making up a higher and growing portion of the resource mix. Recent NERC experience analyzing disturbances involving IBRs, including the Blue Cut Fire and Canyon 2 Fire events, demonstrated that the PRC-002 standard was not providing sufficient data to analyze those disturbances, and that NERC needed to address this reliability gap. Order No. 901, issued in 2023, further highlighted the need for a comprehensive set of Reliability Standard requirements addressing all manner of issues related to IBR performance, operations, and planning, including disturbance monitoring.

Proposed Reliability Standard PRC-028-1 would address the identified reliability gap in PRC-002 by extending comprehensive disturbance monitoring and reporting requirements to IBRs. These requirements are informed by, and reflective of, the unique characteristics of IBRs. Proposed Reliability Standard PRC-028-1 would also ensure sufficient data is available from IBRs to evaluate IBR ride-through performance during system disturbances and to provide data for model validation. Such data may be used as part of future standards work addressing IBR model quality issues and IBR operations and planning studies. Proposed Reliability Standard PRC-002-5 would exclude IBRs from its scope to clarify that standard's continued applicability to synchronous resources. Together, these proposed Reliability Standards would enhance the reliability of the Bulk-Power System by ensuring that adequate data from both synchronous generating resources and IBRs is available to facilitate the analysis of system disturbances.

For these reasons, which are summarized here and stated more fully below, NERC requests that the Commission approve the proposed Reliability Standards, provided in Exhibit A hereto, as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[9]

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III. REGULATORY BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[10] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk-Power System, and with the duty of certifying an ERO that would be charged with developing and enforcing

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[9] NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203, to allow the inclusion of more than two persons on the service list in this proceeding.

[10] 16 U.S.C. § 824o.

mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards.[11] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[12] Section 39.5(a) of the Commission's regulations requires the ERO to file for Commission approval each 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 to make effective.[13]

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA and Section 39.5(c) 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.[14]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[15] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[16] In its ERO

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11 *Id.* § 824(b)(1).

12 *Id.* § 824o(d)(5).

13 18 C.F.R. § 39.5(a).

14 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).

15 Order No. 672 at P 334.

16 The NERC Rules of Procedure are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_3A_SPM_Clean_Mar2019.pdf.

Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain criteria for approving Reliability Standards.[17] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders. Further, a vote of stakeholders and adoption by the NERC Board of Trustees is required before NERC submits the Reliability Standard to the Commission for approval.

IV. THE NEED FOR REVISED DISTURBANCE MONITORING STANDARDS ADDRESSING INVERTER-BASED RESOURCES

A. History of Reliability Standards for Disturbance Monitoring

Monitoring and analysis of grid disturbances plays an important role in assuring Bulk-Power System reliability. The NERC Glossary defines a "Disturbance" as:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.
3. The unexpected change in [Area Control Error] that is caused by the sudden failure of generation or interruption of load.

Disturbance monitoring data can be used to improve the accuracy of planning and operating models and to identify risks to the Bulk-Power System that might not have been previously identified. The collection of this data allows engineers to compare actual system performance with expected system performance under disturbance conditions, thereby allowing engineers to improve the system models that are used for both planning and operating the Bulk-Power System. While the voluntary NERC standards in effect at the time of the August 2003 blackout required

[17] ERO Certification Order at P 250.

the use of recording devices for disturbance analysis, the investigation into the causes of that event underscored the need for enhanced requirements in this area.[18]

In its initial petition for approval of Reliability Standards, NERC submitted the first version of the PRC-002 standard, PRC-002-0, for Commission approval.[19] NERC subsequently replaced this version with PRC-002-1 and PRC-018-1 in a later-filed petition in the same docket.[20] Reliability Standard PRC-002-1 would have required Regional Reliability Organizations to establish requirements for installation of disturbance monitoring equipment and reporting of disturbance data to facilitate analyses of events and verify system models. Reliability Standard PRC-018-1 addressed installation of disturbance monitoring equipment and data reporting. In Order No. 693, the Commission approved Reliability Standard PRC-018-1.[21] However, the Commission identified Reliability Standard PRC-002-1 as a "fill in the blank" standard that should be modified to apply to users, owners, and operators of the Bulk-Power System responsible for providing information, and declined to take action on it.[22] In the order, the Commission directed NERC to consider the comments in the underlying proceeding regarding the need for greater continent-wide consistency in the PRC-002 standard.[23]

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18 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) at 162 (recommending that the use of time-synchronized data records be required, recorders be promptly installed where needed on the system, and that data recording protocols be established to facilitate future monitoring and analysis).

19 *Petition of NERC for Approval of Reliability Standards*, Docket No. RM06-16-000 (Apr. 4, 2006).

20 *Petition of NERC for Approval of Proposed Reliability Standards*, Docket No. RM06-16-000 (Aug. 28, 2006).

21 Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218 at P 1551 (2007) [hereinafter Order No. 693].

22 *Id.* at PP 297, 1455.

23 *Id.* at 1456.

In 2014, NERC submitted a petition for approval of Reliability Standard PRC-002-2.[24] Reliability Standard PRC-002-2 consolidated disturbance monitoring requirements from PRC-002-1 and PRC-018-1 into a single Reliability Standard providing a comprehensive and continent-wide approach to disturbance monitoring data collection. The Commission approved Reliability Standard PRC-002-2 in Order No. 814, issued in 2015.[25] The standard became effective in the United States on July 1, 2016, with later phased-in compliance dates for specific requirements.

In 2021, NERC submitted Reliability Standard PRC-002-3 for Commission approval as part of a larger suite of Reliability Standards revisions for improving the framework for establishing and communicating System Operating Limits.[26] This version of the standard modified the applicability of the PRC-002 standard to remove Planning Coordinators as a responsible entity and replace any references to the Planning Coordinator with the Reliability Coordinator. The Commission approved Reliability Standard PRC-002-3 in March 2022.[27]

In March 2023, NERC submitted the currently effective version of the standard, Reliability Standard PRC-002-4, for Commission approval. Reliability Standard PRC-002-4 reflected a number or revisions to clarify the standard, aid in its administration, and reduce ambiguities and unnecessary burdens. The Commission approved Reliability Standard PRC-002-4 in April 2023,[28] and it became effective in the United States on April 1, 2024.

At the time NERC submitted PRC-002-4 for Commission approval, NERC reported that work was underway to consider further revisions that would address the impacts associated with

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[24] *Petition of NERC for Approval of Proposed Reliability Standard PRC-002-2*, Docket No. RM15-4-000 (Dec. 15, 2014).

[25] *Disturbance Monitoring and Reporting Requirements Reliability Standard,* Order No. 814, 152 FERC ¶ 61,198 (2015).

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

[27] *N. Am. Elec. Reliability Corp.*, Docket No. RD22-2-000 (Mar. 4, 2022).

[28] *N. Am. Elec. Reliability Corp.*, Docket No RD23-4-000 (Apr. 14, 2023) (delegated letter order).

the growing penetration of IBRs on the Bulk-Power System and the findings of recent event reports involving such resources.[29] Proposed Reliability Standards PRC-002-5 and PRC-028-1 represent the conclusion of that work. The following sections provide a summary of the findings and Commission orders that guided the development of these standards.

B. The IRPTF Review of NERC Reliability Standards Identifies the Need to Revise Disturbance Monitoring Requirements to Include IBRs

In 2017, following a series of grid disturbances involving IBRs, NERC developed the Inverter-Based Resource Performance Task Force, or IRPTF. This group undertook a comprehensive review of all NERC Reliability Standards to determine if there were opportunities to address gaps or otherwise improve the standards to assure reliability considering the unprecedented growth of IBRs on the Bulk-Power System. In 2020, the IRPTF published a white paper summarizing the results of its review.[30] In this white paper, the IRPTF recommended revising the PRC-002 Reliability Standard to address the lack of disturbance monitoring data available from IBRs, noting that the lack of such data has led to difficulty in adequately assessing system events involving IBRs, including the Blue Cut Fire and Canyon 2 Fire events.[31]

The IRPTF stated that the PRC-002 Reliability Standard was written "with a focus on synchronous machine dominated systems," and that IBRs are not likely to meet the standard's

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[29] Petition of NERC for Approval of Proposed Reliability Standard PRC-002-4, Docket No. RD23-4-000 at 3-4.

[30] NERC IRPTF, IRPTF Review of NERC Reliability Standards (Mar. 2020), https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf [hereinafter IRPTF White Paper].

[31] IRPTF White Paper at 5. For more information on these events, *see* NERC, *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report: Southern California 8/16/2016 Event* (June 2017), https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf (analyzing the Blue Cut fire event) and NERC and WECC Staff, *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report: Southern California Event: October 9, 2017* (Feb. 2018), https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf.

criteria for identifying the Bulk Electric System ("BES") elements where data monitoring would be required.[32] As such, there may not be sufficient data from these resources to aid in analyzing system disturbances involving IBRs.

Under Reliability Standard PRC-002-4 Requirement R1, the Transmission Owner identifies BES buses with high short circuit MVA values for which sequence of event recording (SER) and fault recording (FR) devices will be required. The methodology for identifying these buses identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data. The BES elements with short circuit MVA in the top 20 percent are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection bus and nearby BES buses are not expected to be in the top 20 percent. Hence, BES buses near these resources are more likely to be omitted from requirements for SER and FR data monitoring.

Similarly, under Reliability Standard PRC-002-4 Requirement R5, the Reliability Coordinator determines which BES elements will require dynamic disturbance recording (DDR) data. Requirement R5 includes size criteria for generating resources and other critical elements such as high voltage direct current, Interconnection Reliability Operating Limits, and elements of an automatic undervoltage load shedding (UVLS) program, for which DDR would be required. For generation resources in particular, Requirement R5 includes requirements for monitoring at sites with either a gross individual nameplate rating of greater than or equal to 500 MVA or gross

32 IPRTF White Paper at 5.

individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. The IRPTF identified that most IBRs do not meet this nameplate rating criteria.

Based on its analysis of the PRC-002 standard, the rapid growth of IBRs on the Bulk-Power System, and experience with past disturbances involving IBRs, the IRPTF concluded that the PRC-002 Reliability Standard "does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices, the location requirements need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances."[33] Shortly after the issuance of the white paper, the IRPTF submitted a Standard Authorization Request to revise the PRC-002 standard.

While work was underway to revise PRC-002, the Commission issued two orders related to IBRs that were relevant to NERC's work: the first directing NERC to expand its registry criteria to include non-Bulk Electric System IBRs, and the second directing NERC to submit a series of proposed new or revised Reliability Standards to address IBR-related reliability issues, including disturbance monitoring issues. These orders are summarized in the following sections.

C. Order 901 Directs NERC to Develop Reliability Standards to Address Concerns Related to IBRs at "All Stages of Interconnection, Planning, and Operations"

1. Overview of Order No. 901

On October 19, 2023, the Commission issued Order No. 901,[34] a final rule directing the development of Reliability Standards to address reliability issues associated with the growth of IBRs on the Bulk-Power System. In the order, and in the preceding notice of proposed rulemaking

33 IRPTF White Paper at 6.

34 Order No. 901.

("NOPR"), the Commission cited multiple ERO resources on IBR issues, including reliability guidelines, white papers, reliability assessments, technical reports, event reports, NERC alerts, and other resources, as underscoring the need for mandatory Reliability Standards to address reliability concerns related to IBRs at "all stages of interconnection, planning, and operations."[35] The Commission concluded that, while NERC, the Commission, and industry groups all had efforts underway to address IBR risks, the Commission directed NERC to address specific reliability gaps because the existing Reliability Standards do not adequately address the reliability risks posed by the increasing numbers of IBRs connecting to the Bulk-Power System.[36] The Commission directed NERC to develop new and revised Reliability Standards to address the following four topic areas of IBR issues: (1) data sharing;[37] (2) data and model validation;[38] (3) planning and operational studies;[39] and (4) performance requirements.[40]

Within these four topic areas, the Commission identified the specific reliability issues that NERC would need to address. In so doing, the Commission distinguished between IBRs currently registered with NERC for compliance purposes, or would be in the future based on revised registry criteria ("registered IBRs");[41] IBRs that are not registered with NERC ("unregistered IBRs") but

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35 *Id.* at P 25.

36 *Id.* at Section III.

37 *See* Order No. 901 at PP 66-109 (discussing directives related to data sharing requirements).

38 *See id.* at PP 110-161 (discussing directives related to data and model validation requirements).

39 *See id.* at PP 162-177 (discussing directives related to planning and operational studies requirements).

40 *See id.* at PP 178-211 (discussing directives related to performance requirements).

41 On November 17, 2022, the Commission issued an order directing NERC to undertake actions to expand the class of IBRs that are required to register with NERC and comply with NERC Reliability Standards. *Registration of Inverter-Based Resources*, 181 FERC ¶ 61,124 (2022) [hereinafter IBR Registration Order]. Specifically, the Commission directed NERC to explain how it will "identify and register owners and operators of IBRs that are connected to the Bulk-Power System, but are not currently required to register with NERC under the Bulk Electric System definition… that have an aggregate material impact on the reliable operation of the Bulk-Power System." *Id.* at P 1 (citations omitted).

The Commission approved NERC's proposed expansion of the Generator Owner and Generator Operator registry criteria to encompass additional IBRs in an order issued June 27, 2024. *Order Approving Revisions to North American Electric Reliability Corporation Rules of Procedure and Requiring Compliance Filing*, 187 FERC ¶ 61,196 (2024) [hereinafter IBR Registration Approval Order].

which need to be modeled for reliability; and IBRs that are connected to the distribution system, but, in the aggregate, can impact Bulk-Power System reliability ("IBR-DERs").[42] NERC was directed to develop responsive standards and submit them to the Commission on a three-year, staggered timeframe.

Additionally, the Commission directed NERC to submit an informational filing, within 90 days of the date of the order, detailing a comprehensive standards development plan and explanation of how NERC would prioritize the development of new or modified Reliability Standards.[43]

2. Order No. 901 Directives for Addressing Disturbance Monitoring Concerns

In Order No. 901, the Commission specifically directed NERC to develop new or revised Reliability Standards to require Generator Owners of registered IBRs to have disturbance monitoring capabilities. Citing the IRPTF White Paper and other NERC disturbance reports and white papers, the Commission directed NERC as follows:

> Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal to direct NERC to include in the new or modified Reliability Standards technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment. We agree with NERC that updating Reliability Standard PRC-002-2 to apply to registered IBRs for disturbance monitoring data collection, including recording sequence of events, digital faults, synchronized phasor measurements, inverter oscillography, inverter and plant-level fault codes, and data retention, could be one way to accomplish this directive. We further agree with the findings in NERC reports (e.g.,

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42 Order No. 901 at P 4 n.14.

43 Order No. 901 at P 222.

> a lack of high-speed data captured at the IBR or plant-level controller and low-resolution time stamping of inverter sequence of event recorder information has hindered event analysis) and direct NERC through its standard development process to address these findings.[44]

Acknowledging comments in the rulemaking proceeding, the Commission further directed NERC to "consider the burdens of generators collecting and providing data, while assuring that Bulk-Power System operators and planners have the data they need for accurate disturbance monitoring and analysis," and "to consider… whether additional IBR data points… are needed to further enhance real-time visibility of Bulk-Power System operations."[45]

With respect to the implementation of the directed standards modifications, the Commission stated, "we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date."[46]

V. NERC'S ORDER NO. 901 WORK PLAN

In Order No. 901, the Commission directed NERC to submit an informational filing, within 90 days of the date of the order, detailing a comprehensive standards development plan and explanation of how NERC would prioritize the development of new or modified Reliability Standards to address the directives set forth in that order.

On January 17, 2024, NERC submitted an Informational Filing that included its Order No. 901 Work Plan.[47] NERC detailed how it will leverage the multiple standards development projects

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[44] *Id.* at P 85 (citations omitted).

[45] *Id.* at P 86 (citing comments).

[46] *Id.* at P 226.

[47] Informational Filing of the North American Electric Reliability Corporation Regarding the Development of Reliability Standards Responsive to Order No. 901, Docket No. RM22-12-000 (Jan. 17, 2024) [hereinafter Order No. 901 Work Plan].

planned or already underway to address IBR-related risks and add new projects as necessary, to ensure that the reliability issues identified by the Commission in Order No. 901 are addressed appropriately through the standards development process. The Order No. 901 Work Plan consists of four key milestones with associated dates for completion, consistent with the Commission's direction in Order No. 901, to help ensure that the process proceeds in an orderly and timely manner. These milestones are summarized below:

- **Milestone 1:** Submission of Order No. 901 Work Plan (completed: January 17, 2024)
- **Milestone 2:** Development and filing of Reliability Standards to address disturbance monitoring data sharing, IBR performance requirements, and post-event performance validation for registered IBRs (completion: November 4, 2024)
- **Milestone 3:** Development and filing of Reliability Standards to address data sharing and model validation for all IBRs (completion: November 4, 2025)
- **Milestone 4:** Development and filing of Reliability Standards to address planning and operational studies requirements for all IBRs (completion: November 4, 2026)

Relevant to this filing, NERC prioritized the following standards development projects to meet the goals set in Milestone 2 of the Order 901 Work Plan:

- Project 2020-06 Verifications of Models and Data for Generators;
- Project 2021-04 Modifications to PRC-002-2 Disturbance Monitoring;
- Project 2020-02 Modifications to PRC-024 (Generator Ride-through); and
- Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues.

The standards projects associated with Milestone 2 address IBR performance during disturbances commonly referred to as "ride-through." These standards would focus on how to adequately monitor, analyze, report, and mitigate IBR performance during the disturbance that occurs in "ride-through" periods.

NERC developed the proposed Reliability Standards addressed in this filing, proposed Reliability Standards PRC-028-1 and PRC-002-5, under Project 2021-04 Modifications to PRC-

002-2 Disturbance Monitoring. As discussed more fully in Section VI, proposed Reliability Standard PRC-028-1 includes new disturbance monitoring data requirements for IBRs, consistent with the recommendations of the IRPTF and the relevant Commission directives from Order No. 901, and proposed Reliability PRC-002-5 includes modifications to exclude IBRs from the scope of that standard. A summary of the Reliability Standards developed to address the Milestone 2 directives is provided below.

A. Project 2020-06 Verifications of Models and Data for Generators

Addressed in a separate filing filed concurrently with this petition, Project 2020-06 Verifications of Models and Data for Generators proposes to establish a new defined term, Inverter-Based Resource (IBR), for inclusion in the *Glossary of Terms used in NERC Reliability Standards*, as follows:

> **Inverter-Based Resource (IBR)**: A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as an inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. Examples include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

The proposed definition of Inverter-Based Resource (IBR) would establish a consistent understanding of the meaning of the term across all NERC Reliability Standards going forward. This term is used throughout the Order No. 901 Work Plan Milestone 2 Reliability Standards discussed below.

B. Project 2021-04 Modifications to PRC-002-2 Disturbance Monitoring

As addressed in this filing, Project 2021-04 Modifications to PRC-002-2 Disturbance Monitoring proposes to establish a new Reliability Standard PRC-028-1, Disturbance Monitoring and Reporting Requirements for IBR, to create new capability-based requirements for IBR disturbance monitoring. The data collected under proposed Reliability Standard PRC-028-1 would be used to inform other Reliability Standards for Milestones 2, 3, and 4, as actual IBR performance is a core component of Order No. 901. In addition, NERC proposes to remove IBR as applicable facilities from PRC-002, as the framework of that standard remains sufficient for synchronous resources.

C. Project 2020-02 Modifications to PRC-024 (Generator Ride-through)

Addressed in a separate filing filed concurrently with this petition, Project 2020-02 Modifications to PRC-024 proposes to establish a new Reliability Standard PRC-029-1, Frequency and Voltage Ride-through Requirements for Inverter-based Resources, to create capability-based and performance-based requirements for IBR ride-through performance. Proposed Reliability Standard PRC-029-1 would "ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions."

Proposed Reliability Standard PRC-029-1 would establish ride-through performance criteria and focus on the evaluation and documentation of ride-through capability. Proposed Reliability Standard PRC-029-1 is generally an event-based standard, though it is also required to provide evidence of the capability to ride-through future grid disturbances by means such as dynamic models and simulation results.

In addition, Project 2020-02, Modifications to PRC-024, proposes to remove IBR from Reliability Standard PRC-024 to maintain capability-based requirements for synchronous generators, synchronous condensers, and asynchronous type 1 and type 2 wind generation.

D. Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues

Addressed in a separate filing filed concurrently with this petition, Project 2023-02, Analysis and Mitigation of BES Inverter-Based Resource Performance Issues, proposes to establish new Reliability Standard PRC-030-1 to create new risk-based requirements for IBR Generator Owners related to IBR performance. Proposed Reliability Standard PRC-030-1 would require Generator Owners to identify any complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a four second period. Generator Owners would then be required to analyze their IBR facility performance during the event, for the purpose of determining the root cause(s) of change(s) in Real Power output; documenting the facility's ride-through performance including Reactive Power response during the event; assessing any performance issues identified and if corrective actions are needed; and determining the applicability of the root cause(s) to the Generator Owner's other IBR facilities. Data from proposed Reliability Standard PRC-028-1 and the ride-through criteria established in proposed Reliability Standard PRC-029-1 would inform the analysis of ride-through performance in proposed Reliability Standard PRC-030-1.

Collectively, the proposed Reliability Standards would enhance the reliability of the BPS by addressing critical IBR reliability issues in accordance with Milestone 2 of NERC's Order No. 901 Work Plan.

VI. JUSTIFICATION FOR APPROVAL: PROPOSED RELIABILITY STANDARD PRC-028-1

Proposed Reliability Standard PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources is a new Reliability Standard that includes disturbance monitoring requirements for IBRs, consistent with the recommendations of the IRPTF and Commission directives from Order No. 901. Together with proposed Reliability Standard PRC-002-5, proposed Reliability Standard PRC-028-1 would advance reliability by ensuring that adequate data from both synchronous generating resources and IBRs is available to facilitate the analysis of disturbances on the Bulk-Power System. Having such data is necessary for system engineers to better understand the root causes and effects of system disturbances and take the appropriate actions to protect system reliability, particularly as the Bulk-Power System transitions from a resource mix consisting primarily of large synchronous resources located near population centers, to one that is increasingly reliant on relatively smaller IBRs that are geographically dispersed. Proposed Reliability Standard PRC-028-1 would also provide high quality data of IBR performance during disturbances that can be leveraged by drafting teams addressing other Commission directives from Order No. 901, such as teams addressing IBR model quality issues in Milestone 3 related standards development projects, as well as IBR operation and planning studies in Milestone 4 related standards development projects.

As explained in Exhibit G, NERC developed the proposed Reliability Standard using NERC's standard development process. This process included multiple public comment and ballot periods. The NERC Board of Trustees adopted the proposed Reliability Standard on October 8, 2024.

In this section, NERC provides a requirement-by-requirement justification of the proposed Reliability Standard, with a summary of the supporting rationale. This section concludes with a discussion of how the proposed Reliability Standard addresses the relevant Commission directives from Order No. 901. Additional information may be found in the Technical Rationale for Proposed Reliability Standard PRC-028-1, included as Exhibit E-2 to this petition, as well as the Complete Record of Development, included as Exhibit G.

A. The Need for a New Reliability Standard Addressing Disturbance Monitoring for IBRs

Proposed Reliability Standard PRC-028-1 reflects the drafting team's determination that drafting a new standard to address the recommendations of the IRPTF and the relevant directives in Order No. 901 for IBR disturbance monitoring requirements would be preferable to revising the currently effective PRC-002 Reliability Standard to include IBRs.

The drafting team concluded that the PRC-002 Reliability Standard, which relies on the application of technically justified methodologies and criteria to identify those BES buses for which disturbance monitoring capabilities are required, adequately serves the purpose of capturing event data to analyze system disturbances. However, disturbances over the past decade involving IBRs (e.g., the Blue Cut Fire,[48] Canyon 2 Fire,[49] and Odessa[50] disturbances) have demonstrated that many IBR respond to a normally cleared, few cycle fault with undesirable performance, which poses risks to system reliability. While the initiating events from these past disturbances were not considered to be large-scale system disturbances, the performance of many IBRs in response to those initiating events resulted in larger system disturbances. Because the PRC-002 Reliability Standard does not account for features more common to IBRs (e.g., contributing low fault current, usually interconnected in more remote parts of the system, smaller nameplate ratings), most of the IBRs involved in those disturbances did not have, and were not required to have, adequate disturbance monitoring data under that standard. As a result, there was not sufficient data to effectively evaluate the IBR plant responses.

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48 *See* NERC, *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report* (June 2017), https://www.nerc.com/pa/rrm/ea/1200_mw_fault_induced_solar_photovoltaic_resource_/1200_mw_fault_induced_solar_photovoltaic_resource_interruption_final.pdf (covering the Blue Cut Fire event on August 16, 2016).

49 *See* NERC and WECC, *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report* (Feb. 2018), https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf (covering the Canyon 2 Fire event on October 9, 2017).

50 *See* NERC and Texas RE, *Odessa Disturbance: Texas Events: May 9, 2021 and June 26, 2021* (Sept. 2021), https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf [hereinafter Odessa Disturbance Report].

To ensure that adequate data would be available from IBRs to facilitate analysis of similar disturbances going forward, as well as to evaluate IBR performance and validate IBR models during such disturbances consistent with the Commission's directives in Order No. 901, the drafting team determined that all applicable IBRs should be required to have disturbance monitoring data. To avoid confusion with the methodology and criteria-based approach of the PRC-002 standard, and in recognition of the broader reliability goals for IBR monitoring, the drafting team determined to create a new Reliability Standard for disturbance monitoring requirements that is specific to IBRs and that reflects the technical considerations associated with effective disturbance monitoring for these resources, given their technical and operational characteristics. The elements of this new Reliability Standard are discussed in the following sections.

B. Title and Purpose

The title of proposed Reliability Standard PRC-028-1 is Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources. The stated purpose of the standard is: "To have adequate data available from Inverter-Based Resources to evaluate Inverter-Based Resource ride-through performance during System Disturbances and to provide data for Inverter-Based Resource model validation."

C. Applicability

Proposed Reliability Standard PRC-028-1 is applicable to Generator Owners that own: (1) BES IBRs; and (2) non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

The proposed standard includes as applicable entities those Generator Owners that own IBRs meeting the Bulk Electric System definition criteria, which have traditionally been subject to registration for compliance with NERC Reliability Standards. It also includes those Generator Owners that own the non-BES IBRs that NERC will register in accordance with revisions to its Rules of Procedure approved by the Commission in 2024.[51] As such, the applicability of proposed Reliability Standard PRC-028-1 is consistent with paragraph 85 of Order No. 901, in which the Commission directed NERC to develop disturbance monitoring requirements for "registered IBR generator owners."[52]

D. Requirement R1

Proposed Reliability Standard PRC-028-1 Requirement R1 establishes requirements for sequence of event recording (SER) data. Sequence of event recorders record equipment response to an event, including opening and closing of breakers and switches to isolate faulted equipment. Proposed Requirement R1 would provide as follows:

> R1. Each Generator Owner shall have sequence of event recording (SER) data for the following Elements that it owns:
>
> 1.1. Circuit breaker position (open/close) for circuit breakers associated with the main power transformer(s)[1], collector bus(es), shunt static and dynamic reactive device(s), and AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to Inverter-Based Resource.
>
> 1.2. For IBR units[2] in commercial operation[3] after the effective date of this standard, the following data shall be recorded when triggered by ride-through operation or tripping of an IBR unit.
>
> 1.2.1. All fault codes.
>
> 1.2.2. All fault alarms.

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51 *See* IBR Registration Approval Order, *supra* note 41. Presently, the NERC *Glossary* defines the Generator Owner as the "Entity that owns and maintains generating Facility(ies)", with the term "Facility" defined as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." NERC has initiated a separate, high priority project, Project 2024-01 Rules of Procedure Definitions Alignment (Generator Owner and Generator Operator), to align the definitions of Generator Owner and Generator Operator in the *Glossary* with the recently approved versions of those terms as used in the NERC Rules of Procedure. The first phase of this project is scheduled for completion in early 2025. Additional information on this project is available at https://www.nerc.com/pa/Stand/Pages/Project-2024-01-Rules-of-Procedure-Definitions-Alignment_GO-and-GOP.aspx.

52 Order No. 901 at P 85.

1.2.3. High and low voltage ride-through mode status.

1.2.4. High and low frequency ride-through mode status.

1.3. For IBR units in commercial operation before the effective date of this standard, if capable, the following data shall be recorded when triggered by ride-through operation or tripping of an IBR unit.

1.3.1. All fault codes.

1.3.2. All fault alarms.

1.3.3. High and low voltage ride-through mode status.

1.3.4. High and low frequency ride-through mode status.

[1] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for Inverter-Based Resources. In case of dedicated VSC HVDC system connecting to an Inverter-Based Resource, a transformer isolating the DC-AC converter from the transmission system is also considered a main power transformer.

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

[3] Commercial operation means achievement of this designation indicating that the facility has received all approvals necessary for operation after completion of initial start-up testing.

Proposed Requirement R1 Part 1.1 would require capturing SER data from all IBR for the specified elements. Change of state of circuit breaker position, time stamped according to proposed Requirement R7 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of the IBR response during a power system disturbance. Analyses of system disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations helps determine the interruption of flows during disturbances.

Proposed Requirement R1 Parts 1.2 and 1.3 would require the Generator Owner to record any fault code or alarm that is generated by operation within ride-through zones or IBR unit tripping. IBR units typically enter a ride-through zone when voltage or frequency deviates beyond certain thresholds. The IBR unit is typically configured to record a change in status whenever it enters or exits a voltage or frequency ride-through zone. The recording of fault codes and alarms can help understand the reasons for which the IBR unit tripped and can help determine if it is a correct or incorrect operation. Some of the typical protective functions used within an IBR unit that may generate a fault code or alarm include: open phase detection, ac and dc overcurrent protection, ac undervoltage and overvoltage protection, dc undervoltage protection, underfrequency and overfrequency protection, rate of change of frequency protection, loss of synchronization, unintentional islanding protection, reverse current protection, dc ground fault protection, ac ground fault protection, or negative sequence current protection.

In drafting these two requirement parts, the drafting team considered that while newer IBR units have the capability to record fault codes, fault alarms, high and low voltage ride-through mode status, and high and low frequency ride-through mode status when triggered by ride-through operation or tripping, older units may not have this capability. Therefore, for those IBR units already in service by the time proposed Reliability Standard PRC-028-1 becomes effective, proposed Requirement R1 Part 1.3 would require the Generator Owner to record the specified data only to the extent the equipment is capable of doing so. This approach is consistent with other Reliability Standards that consider equipment capabilities (see, e.g., Reliability Standard PRC-002-5 Requirement R8) and reflects a measured consideration of the burdens on Generator Owners owning older IBR units compared to the reliability benefits that are expected to be provided by recording the specified data.

E. Requirement R2

Proposed Reliability Standard PRC-028-1 Requirement R2 establishes requirements for fault recording data. Fault recorders record actual waveform data replicating the system primary voltages and currents. Proposed Requirement R2 would provide as follows:

> R2. Each Generator Owner shall have triggered fault recording (FR) data to determine the following electrical quantities for Elements that it owns:

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

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

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

2.1.3. Real and Reactive Power expressed on a three-phase basis.

2.2. Collector feeder breaker FR data:

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

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

2.2.3. Real and Reactive Power expressed on a three-phase basis.

2.3. Shunt dynamic reactive device FR data:

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

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

2.3.3. Reactive Power output expressed on a three-phase basis.

Proposed Requirement R2 requires each Generator Owner to have triggered FR data to determine specified electrical quantities for the Elements that it owns. For effective fault analysis, it is necessary to know values of all phase and residual or neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data augments SERs in evaluating circuit breaker operation. FR also shows generator output response to a system disturbance.

The intent of proposed Requirement R2 is to capture sufficient FR data for Elements at each IBR to analyze the overall response of the IBR to a system disturbance. Analyses of disturbances involving widespread reduction of power output from IBRs in recent years have shown that expansion of monitoring at IBR sites is necessary. The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g., residual or neutral current if the phase currents are directly measured). The FR data captured from IBR units helps in understanding individual IBR unit's response during system disturbances. However, in lieu of requiring FR data from IBR units, the proposed requirement requires FR data from collector feeder breakers. The FR data captured from collector feeder breakers provides information about collective response of IBR units on a given collector feeder during system disturbances.

The plant-level FR measurements (those measured on high-side terminals of the main power transformer, as specified in Requirement R2, Part 2.1) provide performance data for each IBR. To cover all possible fault types, phase-to-neutral voltage recording for each phase is required to be determinable. Each phase current and residual or neutral current are required to distinguish between phase faults and ground faults. This data also facilitates determination of the fault location and cause of relay operation. The measurements of active and reactive power provide data on the overall response of the IBR to the system disturbance.

In some cases, a dynamic reactive device is used within an IBR and is often connected to a medium voltage collector bus. Regardless of where a dynamic reactive device is connected, the output of it during system disturbances is important to understand the overall performance of the plant during a disturbance. The measured or determined electrical quantities for dynamic reactive devices are the same as those specified to be measured/determined from the high-side of the main power transformer.

F. Requirement R3

Proposed Reliability Standard PRC-028-1 Requirement R3 establishes requirements for fault recording data requirements, as follows:

> R3. Each Generator Owner shall have FR data as specified in Requirement R2 that meets the following:
>
> 3.1. High-side of the main power transformer FR data:
>
> 3.1.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.
>
> 3.1.2. A minimum recording rate of 64 samples per cycle.
>
> 3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

3.1.3.3. Overfrequency and underfrequency

3.2. Collector feeder breaker FR data:

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

3.2.2. A minimum recording rate of 64 samples per cycle.

3.2.3. Trigger settings for at least the following:

3.2.3.1. Neutral (residual) overcurrent, if applicable.

3.2.3.2. AC phase overvoltage and undervoltage.

3.2.3.3. Overfrequency and underfrequency.

3.3. Shunt dynamic reactive device FR data:

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

3.3.2. A minimum recording rate of 64 samples per cycle.

3.3.3. Trigger settings for at least the following:

3.3.3.1. Neutral (residual) overcurrent.

3.3.3.2. AC phase overvoltage and undervoltage.

Time stamped pre- and post-trigger FR data aid in the analysis of power system operations and the determination if operations were intended. The NERC/Texas RE report on the Odessa Disturbance recommended high resolution oscillography data at the point of interconnection.[53] Proposed Requirement R3 specifies a minimum recording rate of 64 samples per cycle, recognizing the state-of-the-art for disturbance monitoring equipment, including any storage capability limitations, and provides sufficient data to recreate an accurate response of the IBR to system disturbances.

[53] *See* Odessa Disturbance Report, *supra* note 50, at 30.

Pre- and post-trigger fault data, along with the SER data, time-stamped to a common clock, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Additionally, IBRs employ fast-acting control systems (with built-in protection functions) dictating an IBR's response to a system disturbance. Generally, system faults persist for a short period; approximately 1 to 30 cycles. To capture the full response of IBR spread over a large geographic area, the drafting team determined a two second total minimum record length, synchronized to a common clock, is necessary for FR data. In contrast to only a single record, multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data.

FR triggers can be set so that when the monitored value on the recording device exceeds a trigger value, data is recorded. Requirement R3, Part 3.1.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R3, Part 3.1.3.2 specifies a phase overvoltage or undervoltage trigger during voltage ride-through events. The triggers specified in Requirement R3, Part 3.3 for dynamic reactive device FR data are similar to triggers specified in Requirement R3, Part 3.1 for plant level FR data measurements at the high-side of the main power transformer.

G. Requirement R4

Proposed Reliability Standard PRC-028-1 Requirement R4 establishes requirements for dynamic disturbance recording (DDR) data. Dynamic disturbance recorders capture incidents that portray power system behavior during dynamic events such as low-frequency oscillations and abnormal frequency or voltage excursions. Large scale system disturbances generally comprise an evolving sequence of events that occur over an extended period, making DDR data essential for event analysis.

Proposed Requirement R4 would provide as follows:

R4. Each Generator Owner shall have continuous dynamic disturbance recording (DDR) data and storage to determine the following electrical quantities for each main power transformer(s) it owns:

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

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

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

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

In drafting proposed Requirement R4, the drafting team considered that the state-of-the-art DDR equipment is capable of continuous recording. Data available pre- and post-contingency helps identify the causes of, and IBR response to, system disturbances. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

DDR data contains the dynamic response of an IBR to a system disturbance and is used for analyzing complex power system events. This recording is typically used to capture the dynamic response to short-term and long-term disturbances. Since dynamic response data is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data. DDR data is used to measure transient responses to system disturbances during a relatively balanced post-fault condition. Requirement R4 reflects the measurements that, in the drafting team's determination, would be sufficient for analysis.[54]

A crucial part of disturbance analysis is understanding the dynamic response of generating resources. Therefore, the drafting team determined it is necessary to have DDRs at the high-side of the main power transformer(s) measuring the specified electrical quantities to adequately capture IBR response.

[54] *See* Technical Rationale for PRC-028-1, Exhibit E-2 at 10 for additional discussion.

H. Requirement R5

Proposed Reliability Standard PRC-028-1 Requirement R5 establishes requirements for DDR data parameters, as follows:

> R5. Each Generator Owner responsible for DDR data for the electrical quantities identified in Requirement R4 shall have DDR data that meet the following:
>
> 5.1. Input sampling rate of at least 960 samples per second.
>
> 5.2. Output recording rate of electrical quantities of at least 60 times per second.

In developing proposed Requirement R5, the drafting team determined that an input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, would ensure adequate accuracy for calculation of recorded measurements such as complex voltages and frequency. The input sampling rate specified is the same as the one specified in Reliability Standard PRC-002-5.

The drafting team determined that recorded measurements of at least 60 times per second for output recording rates would provide adequate recording speed to monitor IBR responses during power system disturbances. Since control systems associated with IBR are fast acting, higher frequency recording is necessary to accurately reconstruct events, relative to that required for synchronous resources. An output recording rate of 60 times per second provides this higher frequency recording, while not increasing data storage requirements greatly.

I. Requirement R6

Proposed Reliability Standard PRC-028-1 Requirement R6 establishes requirements for time synchronized data. Proposed Requirement R6 would provide as follows:

> R6. Each Generator Owner shall time synchronize all SER, FR, and DDR data to meet the following:
>
> 6.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

6.2. The IBR unit synchronized device clock accuracy within ± 100 milliseconds of UTC. For all other devices, synchronized device clock accuracy within ± 1 milliseconds of UTC.

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

The drafting team determined that ensuring that the internal clocks for monitoring devices are within ± 1 millisecond accuracy would suffice with respect to providing time synchronized data. Recognizing challenges with distributing synchronizing clock signal to all IBR units within an IBR, IBR units are required to have a synchronized device clock accuracy within ± 100 milliseconds of UTC. The clock accuracy required for IBR plant level data is more stringent than IBR unit level data. IBRs, which are not affected by inertial time constants, make changes in power production very rapidly. To understand and analyze control decisions of multiple IBR during system disturbances and the reasons behind those decisions, there must be a high level of accurate time synchronization, which is reflected in the proposed requirement.

J. Requirement R7

Proposed Reliability Standard PRC-028-1 Requirement R7 establishes requirements for disturbance monitoring data sharing. Proposed Requirement R7 would provide as follows:

R7. Each Generator Owner shall provide all requested SER, FR, and DDR data to its Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC in accordance with the following:

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within 15 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII4 Comma Separated Value (CSV) format following Attachment 1.

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

7.5. DDR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111- 1999 or later.

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

Proposed Requirement R7 is responsive to that part of the Commission's Order No. 901 paragraph 85 directive relating to disturbance monitoring data sharing. Proposed Requirement R7 requires the Generator Owner to provide disturbance monitoring data to Bulk-Power System planners and operators, as well as to NERC and the Regional Entities. Proposed Requirement R7 is similar to the previously approved language in Reliability Standard PRC-002-4 Requirement R11 for disturbance monitoring data sharing, which is also reflected in proposed Reliability Standard PRC-002-5.

Proposed Reliability Standard PRC-028-1 Requirement R7 Part 7.1 specifies a minimum period of 20 calendar days, inclusive of the day the data was recorded, for which the data is to be retrievable. The drafting team considered that data hold requests are usually initiated the same day or next day following a system disturbance; however, it takes a longer time to determine which data from which generating facility needs to be retrieved for event analysis. A 20-calendar day period would provide a reasonable period for communication between various entities regarding the disturbance and need for data retrieval from disturbance monitoring equipment at various generating facilities, while avoiding the burdens that would be associated with a longer retention period. The drafting team further considered that having the data retrievable for the 20 calendar days would be realistic and feasible with state-of-the-art equipment available today.

Proposed Requirement R7 Part 7.2 provides that data would be provided within 15 calendar days of a request unless an extension is granted by the requestor. To facilitate the analysis of system disturbances, it is important that the data is provided to the requestor within a reasonable time. Balancing the comments submitted during the standard development process, the drafting team determined that a requirement to provide the data within 15 calendar days of a request (or the granted extension time) would allow a reasonable amount of time to collect the data and perform any necessary computations or formatting while promoting timely analysis.

Proposed Requirement R7 Parts 7.3 through 7.6 specify data formatting and naming conventions. Disturbance analysis includes reviewing data recording from many devices and entities. Having standardized formatting and naming conventions advances timely and accurate analysis. The formatting and naming convention requirements for SER, FR, and DDR are consistent with the corresponding requirements in proposed Reliability Standard PRC-002-5.

K. Requirement R8

Proposed Reliability Standard PRC-028-1 Requirement R8 establishes requirements for addressing failures of disturbance monitoring recording capabilities. Proposed Requirement R8 would provide as follows:

> R8. Each Generator Owner shall, upon the discovery of a failure of the recording capability for the SER, FR, or DDR data:
>
> - Restore the recording capability within 90 calendar days, or
> - Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

Proposed Requirement R8 is similar to the approved language in currently effective Reliability Standard PRC-002-4 Requirement R12, with minor clarifying revisions which are also reflected in proposed Reliability PRC-002-5. Proposed Reliability Standard PRC-028-1 Requirement R8 would require the Generator Owner to restore the recording capability for SER, FR, or DDR data within 90 calendar days of the discovery of a failure. The drafting team determined that a 90-calendar day period strikes an appropriate balance between providing entities with a reasonable period to restore capability and ensuring that the recording capability is not out of service for an extended duration. If the recording capability cannot be restored within 90 calendar days, the Generator Owner must submit a Corrective Action Plan for restoring recording capability to its Regional Entity and implement it according to the Corrective Action Plan timeframe. Consistent with the currently effective PRC-002 standard, this requirement would maintain ERO Enterprise visibility of extended outage conditions.

L. Consideration of Order No. 901 Directives for Disturbance Monitoring

Proposed Reliability Standard PRC-028-1 is responsive in part to the Commission's directives for disturbance monitoring data in paragraph 85 of Order No. 901.[55] Proposed Reliability Standard PRC-028-1 Requirements R1 through R6 address the first part of the Commission's paragraph 85 directive, directing NERC to include in its proposed Reliability Standard "technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements." As discussed above, the proposed requirements would require the Generator Owner owning applicable IBRs to record sequence of event recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data at various places within the IBR. Proposed Requirement R8 addresses remediation of recording equipment failures. These requirements address the fourth part of the Commission's paragraph 85

[55] Order No. 901 at P 85.

directive as well, to consider the findings of NERC reports in establishing the required parameters for disturbance monitoring data recording.

Proposed Reliability Standard PRC-028-1 Requirement R7 addresses the second part of the Commission's paragraph 85 directive, directing NERC "to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System." As discussed more fully above, proposed Requirement R7 would require the Generator Owner of applicable IBRs to share recorded data with the Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC, upon request. Proposed Requirement R7 also addresses data retention, naming formats, and reporting conventions, which are all necessary components for facilitating timely and accurate disturbance analysis.

The third part of the Commission's paragraph 85 directive, "to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment," will be addressed in the next phase of IBR standards development under NERC's Order No. 901 Work Plan (Milestone 3), addressing IBR model validation.

Proposed Reliability Standard PRC-028-1 reflects a measured consideration of the "burdens of generators collecting and providing data, while assuring that Bulk-Power System operators and planners have the data they need for accurate disturbance monitoring and analysis," as the Commission directed in paragraph 86 of Order No. 901.[56] As discussed more fully above,

[56] Order No. 901 at P 86. In this paragraph, the Commission also directed NERC to "consider through its standards development process whether additional IBR data points (e.g., telemetry collections or other automated platform integrations) are needed to further enhance real-time visibility of Bulk-Power System operations." While additional data points would allow for a more detailed analysis of a disturbance, there is a diminishing rate of return for what can be effectively used by a system operator for Real-time monitoring. As model quality incorporating IBR

the drafting team balanced the need for timely and high quality disturbance monitoring data with the burden recording and providing such data may place on Generator Owners owning applicable IBRs. The proposed requirements reflect a reasoned consideration of comments raised throughout the development process, the recommendations of NERC disturbance reports, currently available data recording technologies, cost burdens, and the reliability needs to be addressed by the proposed standard.

VII. JUSTIFICATION FOR APPROVAL: PROPOSED RELIABILITY STANDARD PRC-002-5

Proposed Reliability Standard PRC-002-5 reflects revisions to the applicability of the standard made necessary by proposed Reliability Standard PRC-028-1, as well as several clarifying and alignment revisions throughout.

As explained in Exhibit G, NERC developed the proposed Reliability Standard using NERC's standard development process. This process included multiple public comment and ballot periods. The NERC Board of Trustees adopted the proposed Reliability Standard on October 8, 2024.

This section provides a summary of the revisions in proposed Reliability Standard PRC-002-5. The revisions are shown in redline in Exhibit A. Additional information may be found in the Technical Rationale for Proposed Reliability Standard PRC-002-5, included as Exhibit E to this petition, as well as the Complete Record of Development, included as Exhibit G.

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performance will be addressed through Milestone 3 related standards development projects and operational studies utilizing IBR performance data will be addressed in Milestone 4 projects, system operators will have significant improvements to their Real-time Assessment and state estimator tools with the data points required in the proposed PRC-028-1.

A. Overview of Revisions

The title of Reliability Standard PRC-002-5 is Disturbance Monitoring and Reporting Requirements. The purpose of the proposed standard remains unchanged: to have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances. The Applicability of the standard is revised to specify that it applies to BES Elements, excluding Inverter-Based Resources. IBRs would be subject to the requirements of proposed Reliability Standard PRC-028-1. A related change is found in Requirement R5, which specifies the criteria by which the Reliability Coordinator identifies the BES Elements that require DDR data. Requirement R5 Part 5.1.1 would provide that <u>synchronous</u> generating resources meeting the criteria must be included. Attachment 1 is also revised to refer to the excluded Facilities.

Revisions in Requirement R11 correspond to the requirements found in proposed Reliability Standard PRC-028-1. Requirement R11 Parts 11.4 and 11.5 would provide that FR or DDR data may be provided in CSV format with appropriate headers, providing another option beyond the currently effective standard. Minor revisions in Requirement R12 would clarify the timing of requirements for addressing failures of recording capability, consistent with the corresponding requirement in proposed Reliability Standard PRC-028-1.

In addition to these revisions, proposed Reliability Standard PRC-002-5 reflects minor stylistic revisions and version updates.

VIII. ENFORCEABILITY OF THE PROPOSED RELIABILITY STANDARDS

The proposed Reliability Standards also include measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[57] Additionally, the proposed Reliability Standards include VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standards. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. Exhibit F provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

IX. EFFECTIVE DATE OF THE PROPOSED RELIABILITY STANDARDS

NERC respectfully requests that the Commission approve the proposed Reliability Standards to become effective as set forth in the proposed Implementation Plan, provided in Exhibit B hereto. The proposed Implementation Plan provides that proposed Reliability Standards PRC-002-5 and PRC-028-1 shall become effective on the first day of the first calendar quarter after the effective date of the Commission's order approving the proposed Reliability Standards. This relatively short implementation period is necessary to establish proposed Reliability Standard PRC-028-1 as the standard governing disturbance monitoring requirements for IBRs. The implementation of proposed Reliability Standard PRC-028-1 would then follow a risk-based, phased-in compliance approach that would have Generator Owners implement disturbance monitoring equipment on their fleets over time, with a focus on addressing BES IBRs first as they present the comparably greater risk to reliability if not equipped with disturbance monitoring capabilities. Generator Owners would be required to comply with all requirements across their fleets by no later than January 1, 2030, consistent with the Commission's guidance to have all IBR

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[57] Order No. 672 at P 327.

standards developed in response to the Commission's directives in Order No. 901 to be implemented prior to 2030.[58]

For BES IBRs, the implementation timeframe is as follows. Generator Owners shall comply with Requirements R1 through R7 for 50% of their existing BES IBRs (i.e. in commercial operation on or before the effective date) within three calendar years of the effective date of PRC-028-1, and 100% of their BES IBRs by January 1, 2030. If a Generator Owner has only one such BES IBR, it shall comply within three calendar years. Generator Owners shall comply with Requirements R1 through R7 for their new BES IBRs within 15 calendar months following the effective date of the standard or by the commercial operation date, whichever is later. Compliance with Requirement R8, relating to addressing failures of recording capability, is required beginning nine months after the effective date of the standard.

For non-BES IBRs, the implementation timeframe is as follows. Generator Owners shall comply with Requirements R1 through R7 for 100% of those non-BES IBRs in commercial operation prior to May 15, 2026 by no later than January 1, 2030. Generator Owners shall comply with Requirements R1 through R7 for their new non-BES IBRs within 15 calendar months following the effective date of the standard or by the commercial operation date, whichever is later. Compliance with Requirement R7, relating to addressing failures of recording capability, is required beginning no later than April 1, 2027.

In developing the proposed implementation timeframe, the drafting team considered the Commission's guidance in Order No. 901, as well as NERC reports regarding the reliability need for disturbance monitoring data for IBRs. The drafting team also considered that proposed Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Generator Owners

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58 Order No. 901 at P 226.

of IBRs, many of whom would be expected to install disturbance monitoring equipment for the first time. Further, a new class of Generator Owners will be registered soon, non-BES IBRs will be subject to compliance with NERC Reliability Standards for the first time, and there is a need to ensure fairness and consistency in the proposed standard's application among similar asset types.

The drafting team further considered that the short time provided between regulatory approval and the effective date of the standard may prove problematic for new IBRs that are in later stages of development; therefore, a 15-month implementation period is provided for those new IBRs to come into compliance.

As part of the standard development process, the drafting team considered factors influencing the reasonableness of the time provided for implementation, including that outages may be required to install the necessary equipment for compliance with the proposed standard. The drafting team considered potential supply issues and vendor availability issues associated with implementing the new requirements across all IBRs. The drafting team also considered that the implementation plan for Reliability Standard PRC-002-2, a predecessor to proposed Reliability Standard PRC-002-5, provided entities six years to come into compliance with new requirements for disturbance monitoring equipment, and equipment was only needed at sites identified as meeting the PRC-002 criteria.[59] By contrast, proposed Reliability Standard PRC-028-1 would require entities to install disturbance monitoring equipment on all of their applicable IBRs, and this standard must be implemented prior to 2030 in accordance with Order No. 901.[60]

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[59] *See* Implementation Plan for Reliability Standard PRC-002-2, https://www.nerc.com/pa/Stand/Project%20200711%20Disturbance%20Monitoring%20DL/2007-11_DM_Imp_Plan_2014Sep01_clean.pdf. The Commission approved this implementation plan in Disturbance Monitoring and Reporting Requirements Reliability Standard, Order No. 814, 152 FERC ¶ 61,198 (2015).

[60] NERC estimates that up to approximately 591 registered Generator Owners own Bulk Electric System solar or wind facilities that may be subject to the proposed standard. This preliminary estimation is based on the results of NERC's 2024 Section 1600 confirmation process by which registered entities are required to confirm annually whether they meet the reporting criteria of ongoing Section 1600 data requests (GADS, GADS Wind, GADS Solar,

Based on Order No. 901, the drafting team established January 1, 2030 as the date by which entities must be fully compliant with proposed Reliability Standard PRC-028-1. However, comments received throughout the standard development process suggested this period may not be sufficient for all circumstances.[61] For example, supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside an entity's control may preclude its ability to comply with the proposed standard for one or more of its IBRs in a timely manner.

For that reason, the drafting team, working with NERC staff, included within the proposed implementation plan a process by which Generator Owners may request an extension from the compliance dates provided in the plan if circumstances beyond the Generator Owner's control precluded a timely implementation. Such extensions would be sought by Generator Owners and granted by the Compliance Enforcement Authority on a case-by-case basis. Any such request must include: (1) identification of the IBR for which the Generator Owner requests the extension; (2) a plan for installing the required equipment and a timetable for completion; (3) a description of the

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GMD, MIDAS, and TADS) based on their registered functions. Generator Owners with solar facilities of installed nameplate capacity of 100 MW or more with a commercial operation date of January 1, 2010 or later are required to report in 2024; this reporting threshold will decrease to 20 MW or greater in 2025. Generator Owners with wind facilities with an installed nameplate capacity of 75 MW or greater with a commercial operation date of January 1, 2005 or later are required to report. Additional data and analysis would be required to determine the actual number of Generator Owners owning BES IBRs that would be subject to the standard.

NERC notes that there is presently wide variation in the estimated number of Generator Owners owning non-BES facilities that may be subject to the standard. In June 2024, NERC estimated, based on EIA-860M monthly data, that the Generator Owners of approximately 588 (low) – 922 (high) non-BES facilities may meet the registry criteria for non-BES IBRs. Based on the preliminary results of a recent Request for Information issued by NERC, there may be as many as 1,076 current or planned/future facilities that may meet the revised registry criteria for non-BES IBRs. NERC continues to refine its estimations based on new data. Updated information will be provided in NERC's quarterly IBR Work Plan progress updates filed in Docket No. RD22-4-001.

[61] *See, e.g.*, Exhibit G Complete Record of Development at item 53 (March 18, 2024 Consideration of Comments) at 123-144 (multiple commenters expressing concern with an implementation timeline of less than six years).

circumstances precluding the timely installation of the required equipment and how those circumstances are beyond the control of the entity; and (4) any other relevant information requested by the Compliance Enforcement Authority. If the request is granted, the Generator Owner shall implement the plan in accordance with its provided timetable. If additional time is needed, an updated request shall be submitted.

The inclusion of this extension process in the proposed implementation plan for Reliability Standard PRC-028-1 is just and reasonable. In Order No. 672, the Commission stated that it would consider how an implementation proposal balances "any urgency in the need to implement [a standard] against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability." [62] In recognition of the urgency of addressing the underlying reliability issues, the proposed implementation plan provides a shorter timeframe for full implementation of the proposed Reliability Standard PRC-028-1 requirements than the Commission previously approved for the PRC-002 standard. With diligence, the timeframe should be sufficient and reasonable for Generator Owners to accomplish the significant work that is likely to be required. However, in the individual instances where this timeframe would not be sufficient nor reasonable due to circumstances beyond the Generator Owner's control, a case-by-case extension process would exist to provide relief. The Commission has previously approved Reliability Standards including similar provisions, by which an entity may seek additional time to perform a required action due to circumstances beyond its control. For example, Reliability Standard TPL-007-4 Requirements R7 and R11 each include a provision by which entities may seek an extension from the timelines

[62] *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.")

governing the implementation of Corrective Action Plans addressing system performance issues during geomagnetic disturbance (GMD) events due to circumstances beyond their control.[63] As installation of disturbance monitoring equipment represents a one-time event, NERC determined that a similar extension process would not be appropriate in the proposed PRC-028-1 standard, but that provisions should be made in the implementation plan instead.

As the ERO, it is NERC's responsibility to oversee the Regional Entities to which it has delegated its authorities for the compliance and enforcement of Reliability Standards. NERC would work with the Regional Entities to develop a framework for evaluating any extension requests submitted in accordance with the proposed implementation plan in a fair and consistent manner across the ERO Enterprise. NERC would also monitor the use of this process and the disposition of requests as the proposed standard is implemented. To the extent NERC determines any further action would be prudent, it would be dependent on the volume and nature of the requests received. NERC will consult with FERC staff as it performs this oversight activity.

For the reasons stated above, the proposed implementation plan for the proposed Reliability Standards is just and reasonable, consistent with Commission guidance in Order No. 672, and responsive to the Commission's guidance for the implementation of IBR standards in Order No. 901. NERC respectfully requests approval of the proposed implementation plan as submitted by NERC.

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[63] Reliability Standard TPL-007-4, Transmission System Planned Performance for Geomagnetic Disturbance Events, https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-007-4.pdf.

X. CONCLUSION

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

- proposed Reliability Standards PRC-002-5 and PRC-028-1, and the associated elements included in Exhibit A, effective as proposed herein;
- the proposed Implementation Plan included in Exhibit B; and
- the retirement of Reliability Standard PRC-002-4 effective as proposed herein.

Respectfully submitted,

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Date: November 4, 2024

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A

Proposed Reliability Standards

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-1

Proposed Reliability Standard PRC-002-5
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 a final posting.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
25-day formal or informal comment period with additional ballot	March 18, 2024 – April 11, 2024
15-day formal or informal comment period with additional ballot	May 31, 2024 – June 17, 2024
22-day formal or informal comment period with additional ballot	July 22, 2024 – August 12, 2024
7-day final ballot	September 12, 2024 – September 18, 2024
Board adoption	October 15, 2024

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

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

Term(s):

The terms Inverter-Based Resource (IBR) refer to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of Inverter-Based Resource is:

Inverter-Based Resource (IBR): A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-5
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
   - **4.2. Facilities:** BES Elements, excluding Inverter-Based Resources.[1]
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

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

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

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

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

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

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES

[1] Disturbance monitoring and reporting requirements for Inverter-Based Resources are addressed in PRC-028.

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

buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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

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

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

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

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

3.2.2. Transmission Lines.

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

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

4.1. A single record or multiple records that include:

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

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

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1)

documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

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

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

5.1.1. Synchronous generating resource(s) with:

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

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

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

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

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

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

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

5.2.1. One BES Element; and

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

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

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

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

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

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

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

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

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

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

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

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

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

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

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

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

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of the Reliability Standard PRC-002-2[3] and is not capable of continuous recording, triggered records

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

must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

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

- Rate of change of frequency trigger set at:

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

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

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

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

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

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

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

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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

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

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

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

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

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

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

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

11.5. DDR data will be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

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

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

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

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

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

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

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

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

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

calendar years.

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

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

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

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

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

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

Violation Severity Levels

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

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

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

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

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

	than 100 percent of the total recording properties as specified in Requirement R9.	equal to 80 percent of the total recording properties as specified in Requirement R9.	than or equal to 70 percent of the total recording properties as specified in Requirement R9.	percent of the total recording properties as specified in Requirement R9.
R10	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent, but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent, but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent, but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than one to 10 calendar days late. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 11 to 20 calendar days late. OR The Transmission Owner or Generator Owner as directed by Requirement	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 21 to 30 calendar days late. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days late. OR The Transmission Owner or Generator Owner as directed by Requirement

	directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided less than or equal to 70 percent of the data in the proper data format.
R12	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement

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

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

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

G. References

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

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

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

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

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

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

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC Oder Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14, 2023	Effective Date	April 1, 2024
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

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

(Requirement R1)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

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

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

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

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

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

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

High Level Requirement Overview

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

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

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

Requirement	Entity	Implementation
R13	TO | GO	X

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-1

Proposed Reliability Standard PRC-002-5
Redline to Last Approved (PRC-002-4)

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 a final posting.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
25-day formal or informal comment period with additional ballot	March 18, 2024 – April 11, 2024
15-day formal or informal comment period with additional ballot	May 31, 2024 – June 17, 2024
22-day formal or informal comment period with additional ballot	July 22, 2024 – August 12, 2024
7 day final ballot	September 12, 2024 – September 18, 2024
Board adoption	October 15, 2024

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

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

Term(s):

~~N/A.~~ The terms Inverter-Based Resource (IBR) refer to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of Inverter-Based Resource is:

Inverter-Based Resource (IBR): A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-54
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
   - **4.2. Facilities:** BES Elements, excluding Inverter-Based Resources.[1]
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

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

- **1.1.** Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-54, Attachment 1.
- **1.2.** Notify the other owners of BES Elements directly connected[2] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.
- **1.3.** Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-54, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

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[1] Disturbance monitoring and reporting requirements for Inverter-Based Resources are addressed in PRC-028.

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

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

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

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

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

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

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

3.2.2. Transmission Lines.

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

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

4.1. A single record or multiple records that include:

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

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

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

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

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

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

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

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

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

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

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

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

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

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

5.2.1. One BES Element; and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

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

- Rate of change of frequency trigger set at:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

~~**11.4.**~~**11.5.** DDR data will be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

~~**11.5.**~~**11.6.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

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

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

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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. ~~Data~~Evidence Retention:

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

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

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

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

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

The Generator Owner shall retain evidence of Requirement R7, ~~Measure M7~~ for three calendar years.

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

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

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

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

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

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

~~**1.4. Additional Compliance Information**~~

~~None.~~

Violation Severity Levels

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

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

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

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

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

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

	the requested data more than one to 10 calendar days late~~30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority~~. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	requested data more than 11 to 20 calendar days late~~40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority~~. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	the requested data more than 21 to 30 calendar days late~~50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority~~. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	provided the requested data more than 30 calendar days late~~60 calendar days after the request, unless an extension was granted by the requesting authority~~. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided less than or equal to 70 percent of the data in the proper data format.
R12	The Transmission Owner or Generator Owner as directed by Requirement	The Transmission Owner or Generator Owner as directed by Requirement	The Transmission Owner or Generator Owner as directed by Requirement	The Transmission Owner or Generator Owner as directed by Requirement

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

		Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months, but less than or equal to 12 months.	per Requirement R5, Part 5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

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

G. References

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

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

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

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

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

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

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC Oder Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14, 2023	Effective Date	April 1, 2024
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

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

(Requirement R1)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

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

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

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

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

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

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

High Level Requirement Overview

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

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

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

Requirement	Entity	Implementation
R13	TO | GO	X

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit A-2

Proposed Reliability Standard PRC-028-1
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 a final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
25-day formal or informal comment period with additional ballot	March 18, 2024 – April 11, 2024
15-day formal or informal comment period with additional ballot	May 31, 2024 – June 17, 2024
22-day formal or informal comment period with additional ballot	July 22, 2024 – August 12, 2024
7-day final ballot	September 12, 2024 – September 18, 2024
Board adoption	October 15, 2024

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

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

Term(s):

The terms Inverter-Based Resource (IBR) refer to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of Inverter-Based Resource is:

Inverter-Based Resource (IBR): A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

2. **Number:** PRC-028-1

3. **Purpose:** To have adequate data available from Inverter-Based Resources to evaluate Inverter-Based Resource ride-through performance during System Disturbances and to provide data for Inverter-Based Resource model validation.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.2. Facilities:

   4.2.1 BES Inverter-Based Resources

   4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

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

B. Requirements and Measures

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

1.1. Circuit breaker position (open/close) for circuit breakers associated with the main power transformer(s)[1], collector bus(es), shunt static and dynamic reactive device(s), and AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to Inverter-Based Resource.

1.2. For IBR units[2] in commercial operation[3] after the effective date of this standard, the following data shall be recorded when triggered by ride-through operation or tripping of an IBR unit.

[1] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for Inverter-Based Resources. In case of dedicated VSC HVDC system connecting to an Inverter-Based Resource, a transformer isolating the DC-AC converter from the transmission system is also considered a main power transformer.
[2] IBR unit includes the inverter, converter, wind turbine generator, or high voltage direct current converter connecting generating resource to alternating current Transmission network.
[3] Commercial operation means achievement of this designation indicating that the facility has received all approvals necessary for operation after completion of initial start-up testing.

1.2.1. All fault codes.

1.2.2. All fault alarms.

1.2.3. High and low voltage ride-through mode status.

1.2.4. High and low frequency ride-through mode status.

1.3. For IBR units in commercial operation before the effective date of this standard, if capable, the following data shall be recorded when triggered by ride-through operation or tripping of an IBR unit.

1.3.1. All fault codes.

1.3.2. All fault alarms.

1.3.3. High and low voltage ride-through mode status.

1.3.4. High and low frequency ride-through mode status.

M1. The Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1. Evidence may include, but is not limited to: (1) actual data recordings; or (2) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings. The evidence to show IBR unit capability to record fault codes, alarms, or ride-through mode status may include, but is not limited to: (1) equipment specification, (2) letter from equipment manufacturer, or (3) documents describing lack of recording capability.

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

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

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

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

2.1.3. Real and Reactive Power expressed on a three-phase basis.

2.2. Collector feeder breaker FR data:

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

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

2.2.3. Real and Reactive Power expressed on a three-phase basis.

2.3. Shunt dynamic reactive device FR data:

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

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

2.3.3. Reactive Power output expressed on a three-phase basis.

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

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

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

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

3.1.2. A minimum recording rate of 64 samples per cycle.

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

3.1.3.3. Overfrequency and underfrequency

3.2. Collector feeder breaker FR data:

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

3.2.2. A minimum recording rate of 64 samples per cycle.

3.2.3. Trigger settings for at least the following:

3.2.3.1. Neutral (residual) overcurrent, if applicable.

3.2.3.2. AC phase overvoltage and undervoltage.

3.2.3.3. Overfrequency and underfrequency.

3.3. Shunt dynamic reactive device FR data:

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

3.3.2. A minimum recording rate of 64 samples per cycle.

3.3.3. Trigger settings for at least the following:

3.3.3.1. Neutral (residual) overcurrent.

3.3.3.2. AC phase overvoltage and undervoltage.

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

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

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

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

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

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

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

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

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

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

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

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

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

6.2. The IBR unit synchronized device clock accuracy within ± 100 milliseconds of UTC. For all other devices, synchronized device clock accuracy within ± 1 milliseconds of UTC.

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

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

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within 15 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII[4] Comma Separated Value (CSV) format following Attachment 1.

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

7.5. DDR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

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

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

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

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

[4] American Standard Code for Information Interchange

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

C. Compliance

1. Compliance Monitoring Process

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

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

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

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

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

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the circuit breaker(s) identified in Requirement R1.
R2	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.
R3	The Generator Owner had FR data that meets more	The Generator Owner had FR data that meets more	The Generator Owner had FR data that meets more	The Generator Owner had FR data that meets less

	than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	than or equal to 60 percent of the total recording parameters as specified in Requirement R3.
R4	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.
R5	The Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

R6	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.
R7	The Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data one to 10 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 90 percent of the data, but less than 100 percent of	The Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data 11 to 20 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 80 percent of the data, but less than or equal to 90 percent	The Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data 21 to 30 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 70 percent of the data, but less than or equal to 80	The Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 30 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided less than or equal to 70 percent of the data in the proper data format.

	the data in the proper data format.	of the data in the proper data format.	percent of the data in the proper data format.	
R8	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

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

NERC Reliability Standard PRC-028-1: Technical Rationale.

G. References

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

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

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

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

NERC Reliability Standard PRC-002-5.

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

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

Version History

Version	Date	Action	Change Tracking
0	TBD	Developed by Project 2021-04 Drafting Team	New

Attachment 1

Sequence of Events Recording (SER) Data Format

(Requirement R7, Part 7.3)

Date, Time, Local Time Code, Plant Name, Device[5], State[6]

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

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

08/27/23, 23:58:57.217, -5, Plant name 1, IBR unit 1, undervoltage ride-through mode

08/27/23, 23:58:57.214, -5, Plant name 2, IBR unit 2, dc overcurrent trip

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

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

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit B

Implementation Plan

Implementation Plan

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

Applicable Standard(s)

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

Requested Retirement(s)

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

Applicable Entities

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

General Considerations

Additional time to implement Reliability Standard PRC-002-5 is not provided because the revisions are clarifying in nature to exclude Inverter-Based Resources (or "IBRs) from PRC-002 applicability as they are included in PRC-028. The revision to PRC-002 does not require any additional procurement or installation of Disturbance Monitoring Equipment.

Reliability Standard PRC-028-1 is expected to have wide ranging impact on GOs, as many existing and new facilities would be required to have Disturbance Monitoring Equipment. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities. The implementation plan takes into account scheduling outages needed to implement sequence of events recording, fault recording, and dynamic disturbance recording capability. The implementation plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities.

The ERO enterprise acknowledges that Generator Owners and Generator Operators owning or operating Bulk-Power System connected IBRs that do not meet NERC's current definition of Bulk Electric System ("BES") will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, this implementation plan provides additional time for both new and existing registered entities to come into compliance with Reliability Standard PRC-028-1 for their applicable Inverter-Based Resources not meeting BES definition. In so doing, this implementation plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the Bulk-Power System.

The implementation plan recognizes the Federal Energy Regulatory Commission's directive to have this standard effective and enforceable before 2030.[1]

Effective Date of PRC-002-5

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

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-002-5 shall become effective 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.

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

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

Reliability Standard PRC-028-1

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

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

BES Inverter-Based Resources

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

[1] See Order No. 901 at P226.

For BES Inverter-Based Resources in commercial operation[2] on or before the effective date: Entities shall comply with Requirements R1 through R7 at 50% of their BES Inverter-Based Resources within three (3) calendar years of the effective date of PRC-028-1 and 100% of their BES Inverter-Based Resources by January 1, 2030.

Entities that are required to monitor only one (1) BES Inverter-Based Resource shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of Reliability Standard PRC-028-1.

For BES Inverter-Based Resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later. As an example: Assume the effective date of the PRC-028-1 is July 1, 2025:

- For BES IBRs entering commercial operation after July 1, 2025, but on or before October 1, 2026, entities shall comply with Requirements R1 through R7 by October 1, 2026.
- For BES IBRs entering commercial operation after October 1, 2026, entities shall comply with Requirements R1 through R7 on the commercial operation date.

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than nine (9) months after the effective date of Reliability Standard PRC-028-1.

Non-BES Inverter-Based Resources

The "Non-BES Inverter-Based Resources" are those that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

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

For non-BES Inverter-Based Resources in commercial operation on or before May 15, 2026: Entities shall comply with Requirements R1 through R7 at 100% of their non-BES Inverter-Based Resources by January 1, 2030.

For non-BES Inverter-Based Resources in commercial operation after May 15, 2026:

[2] Commercial operation means achievement of this designation indicating that the facility has received all approvals necessary for operation after completion of initial start-up testing.

Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later.

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than April 1, 2027.

Process for Requesting an Extension from Compliance Dates

Each GO that owns one or more applicable Inverter-Based Resources that are in commercial operation before the effective date of Reliability Standard PRC-028-1 may request an extension from the above-listed compliance dates if circumstances beyond its control prevent the installation of Disturbance Monitoring Equipment on one or more of its Inverter-Based Resources.

To request an extension, the entity shall develop and submit to its Compliance Enforcement Authority[3] a request for extension that contains at a minimum the following information:

1.1. Identification of the Inverter-Based Resource(s) for which the entity requests the extension;

1.2. A plan for installing the Disturbance Monitoring Equipment and a timetable for completion;

1.3. A description of the circumstances precluding the timely installation of Disturbance Monitoring Equipment and how those circumstances are beyond the control of the entity; and

1.4. Any other information the entity deems relevant to the Compliance Enforcement Authority's consideration of its request.

Circumstances beyond the entity's control may include supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside the entity's control.

The entity shall provide any information requested by the Compliance Enforcement Authority to validate the information provided above, including any information specified by the Compliance Enforcement Authority in a supporting process document. If the extension request is granted, the entity shall implement the plan in accordance with the provided timetable. Should additional time be required, the entity shall submit an updated request to its Compliance Enforcement Authority.

Requests should be submitted as soon as the entity identifies circumstances impeding the timely implementation of Reliability Standard PRC-028-1, but no later than three months prior to the compliance date for which the entity requests an extension.

[3] The extension requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

Retirement Date

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

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C

Order No. 672 Criteria

EXHBIIT C

<u>Order No. 672 Criteria</u>

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 Standards have 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]

Disturbance monitoring data can be used to improve the accuracy of planning and operating models and to identify risks to the BPS that might not have been previously identified. The PRC-002 Reliability Standard provides a series of requirements for collecting different types of disturbance monitoring data at locations on the Bulk Electric System ("BES") and for periodically re-assessing those locations for continued validity. The standard addresses the collection of sequence of recording (SER) data, fault recording (FR) data, and dynamic Disturbance recording (DDR) data, data types which can provide useful information in analyzing large system

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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, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) [hereinafter Order No. 672].

2 *See* Order No. 672, *supra* note 1, at P 321 ("The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.").

See Order No. 672, *supra* note 1, at P 324 ("The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.").

disturbances. Experience analyzing disturbances involving Inverter-Based Resources (IBRs), however, has indicated that the PRC-002 has not provided sufficient data to understand how IBR resources have performed during those disturbances. This is because the PRC-002 Reliability Standard was originally written with a focus on synchronous machine dominated systems, and IBRs, which comprise an ever growing portion of the North American resource mix, are not likely to meet the standard's criteria for identifying the BES elements where data monitoring would be required.

Proposed Reliability Standard PRC-028-1 would address an identified reliability gap by extending comprehensive disturbance monitoring and reporting requirements to all IBRs that are, or will be, subject to compliance with NERC Reliability Standards. These requirements are informed by, and reflective of, the unique characteristics of IBRs. Data collected under the proposed standard would be used to evaluate IBR ride-through performance during disturbances and provide data for IBR model validation, so that operators and planners may better account for IBR performance in the future. Proposed Reliability Standard PRC-002-5 would clarify that standard's continued applicability to synchronous resources so that it may continue to serve its purpose of collecting data to understand large system disturbances. Together, the proposed Reliability Standards would advance the reliability of the Bulk-Power System by ensuring that adequate data from both synchronous generating resources and IBRs is available to facilitate the analysis of system disturbances. Proposed Reliability Standard PRC-028-1 would also ensure sufficient data is available from IBRs to evaluate IBR ride-through performance during system disturbances and to provide data for model validation. The proposed Reliability Standards are thus designed to achieve a specific reliability goal and contain a technically sound means to achieve that goal.

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 Standards are clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Proposed Reliability Standard PRC-028-1 would apply to Generator Owners owning IBRs that either meet the NERC Bulk Electric System definition or otherwise qualify for registration as users, owners, or operators of the BPS under the newly applicable criteria for registering owners of non-BES IBRs. Proposed Reliability Standard PRC-002-5 would continue to apply to Reliability Coordinators, Transmission Owners, and Generator Owners, but BES Elements, which are addressed in proposed PRC-028-1, would be excluded from the list of applicable facilities. The proposed Reliability Standards clearly articulate the actions that applicable entities must take to comply with the standards.

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 Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment, as discussed further in **Exhibit F**. The assignment of the severity level for each VSL is consistent with the corresponding requirement, and the VSLs should 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

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[3] *See* Order No. 672, *supra* note 1, at P 322 ("The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.").
See Order No. 672, *supra* note 1, at P 325 ("The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.").

[4] *See* Order No. 672, *supra* note 1, at P 326 ("The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.").

violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

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

The proposed Reliability Standards contain 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]

The proposed Reliability Standards achieve their reliability goals effectively and efficiently in accordance with Order No. 672. Proposed Reliability Standard PRC-028-1 would provide robust and technically justified requirements for IBRs to implement and maintain disturbance monitoring recording capabilities so that IBR performance during system disturbances may be better assessed in the future, and to share such data with reliability entities upon request. In drafting proposed Reliability Standard PRC-028-1, the drafting team struck an appropriate balance between the reliability need for high quality disturbance monitoring data from IBRs and minimizing undue burdens on the Generator Owners responsible for collecting such data. Proposed Reliability Standard PRC-002-5, which is only minimally revised, would continue to achieve its reliability

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[5] *See* Order No. 672, *supra* note 1, at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

[6] *See* Order No. 672, *supra* note 1, at P 328 ("The proposed Reliability Standard does not necessarily have to reflect the optimal method, or 'best practice,' for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.").

goals effectively and efficiently, with consideration to the new requirements for IBRs specified in proposed Reliability Standard PRC-028-1.

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.[7]

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. In accordance with the Commission's direction in Order No. 901,[8] proposed Reliability Standard PRC-028-1 reflects a measured and reasoned consideration of the need for IBR disturbance monitoring data and the technical and operational characteristics of IBRs, balanced against the implementation burden on entities. Proposed Reliability Standard PRC-028-1 would provide important data on IBR performance that has not been available to analyze past system disturbances involving IBRs. Proposed Reliability Standard PRC-002-5 is only minimally revised to reflect the addition of proposed Reliability Standard PRC-028-1 to the suite of requirements for disturbance monitoring and continues to remain consistent with this criteria.

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7 *See* Order No. 672, *supra* note 1, at P 329 ("The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called 'lowest common denominator'—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.").

See Order No. 672, *supra* note 1, at P 330 ("A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a 'lowest common denominator' Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.").

8 Order No. 901, Reliability Standards to Address Inverter-Based Resources, 185 FERC ¶ 61,042 (2023) [hereinafter Order No. 901].

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 Standards would apply consistently throughout North America and do not favor one geographic area or regional model. While the penetration of IBRs may vary by region, proposed Reliability Standard PRC-028-1 would apply to all IBRs due to the need to better understand their performance during system disturbances.

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 Standards 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 reliability need for different disturbance monitoring requirements for synchronous generation (proposed PRC-002-5) and IBR generation (proposed PRC-028-1) is well documented in multiple disturbance reports as highlighted in Order No. 901, and the differences in the specific recording requirements and locations is justified by the technical and operational characteristics of the IBRs. The proposed standards would require the same performance by each of the applicable entities.

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[9] *See* Order No. 672, *supra* note 1, at P 331 ("A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational 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.").

[10] *See* Order No. 672, *supra* note 1, at P 332 ("As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.").

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

The implementation plan for the proposed Reliability Standards is just and reasonable and appropriately balances the urgency in the need to implement the standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures or other relevant capability. The proposed implementation plan provides that the proposed Reliability Standards would become effective on the first day of the first calendar quarter after the effective date of the Commission's order approving the proposed Reliability Standards. This relatively short implementation period is necessary to establish proposed Reliability Standard PRC-028-1 as the standard governing disturbance monitoring requirements for IBRs. The implementation of proposed Reliability Standard PRC-028-1 would then follow a risk-based, phased-in compliance approach that would have Generator Owners implement disturbance monitoring equipment on their fleets over time, with a focus on addressing BES IBRs first as they present the comparably greater risk to reliability if not equipped with disturbance monitoring capabilities. Generator Owners would be required to comply with all requirements across their fleets by no later than January 1, 2030, consistent with the Commission's guidance to have all IBR standards developed in response to the Commission's directives in Order No. 901 to be implemented prior to 2030.[12]

The proposed implementation plan is attached as **Exhibit B** to this petition. As discussed more fully in Section VIII of NERC's petition, the proposed implementation plan reflects a measured consideration of the factors influencing the reasonableness of the time provided for

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[11] *See* Order No. 672, *supra* note 1, 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.").

[12] Order No. 901 at P 226.

implementation, including the potential need for scheduled outages, supply chain and vendor availability, recent changes in the framework by which NERC registers entities for purposes of compliance with Reliability Standards, and the timeframes provided in past implementation plans for implementing similar requirements. These factors are carefully balanced against the demonstrated reliability need to implement these requirements.

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 Standards were developed in accordance with NERC's Commission-approved processes for developing and approving Reliability Standards. **Exhibit G** includes a summary of the Reliability Standard development proceedings*,* and details the processes followed to develop the proposed Reliability Standards. 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.[14]

NERC has identified no competing public interests regarding the request for approval of this proposed Reliability Standards. No comments were received that indicated that the proposed Reliability Standards conflict with other vital public interests.

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[13] *See* Order No. 672, *supra* note 1, at P 334 ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.").

[14] *See* Order No. 672, *supra* note 1, at P 335 ("Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.").

12. Proposed Reliability Standards must consider any other appropriate factors.[15]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

[15] *See* Order No. 672, *supra* note 1, at P 323 ("In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.").

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit D

Consideration of Order No. 901 Directives

Considerations of FERC Order 901 Directives

Directive Language	Consideration of Directives
P 85: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal to direct NERC to include in the new or modified Reliability Standards technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment. We agree with NERC that updating Reliability Standard PRC-002-2 to apply to registered IBRs for disturbance monitoring data collection, including recording sequence of events, digital faults, synchronized phasor measurements, inverter oscillography, inverter and plant-level fault codes, and data retention, could be one way to accomplish this directive. We further agree with the findings in NERC reports (e.g., a lack of high-speed data captured at the IBR or plant-level controller and low-resolution time stamping of inverter sequence of event recorder information has hindered event analysis) and direct NERC through its standard development process to address these findings."	The directive is addressed by new Reliability Standard PRC-028-1 which applies to • BES IBRs – Inclusion I4 of BES definition • Non-BES IBRs - Either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. The drafting team determined that introducing inverter-based resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, a new Reliability Standard PRC-028-1 for monitoring requirements for Inverter-Based Resources is created instead of revising the Reliability Standard PRC-002. The Reliability Standard PRC-028-1, Requirements R1 through R6 obligates Transmission Owner and Generator Owner of Inverter-Based Resources to install Disturbance Monitoring Equipment to record sequence of event recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data at various places within the Inverter-Based Resource. The Reliability Standard PRC-028-1, Requirement R7 obligates Transmission Owner and Generator Owner of Inverter-Based Resources to share recorded data with Transmission Planner, Planning Coordinator, Transmission Operator, Balancing

	Authority, Reliability Coordinator, Regional Entity, or NERC upon request.
P 86: "As a general matter, we agree with ACP/SEIA regarding the need to balance the burden to generator owners of collecting and providing data collected by disturbance monitoring equipment with the benefit of that data to reliability. Thus, in developing the directed data collection requirements, we direct NERC to consider the burdens of generators collecting and providing data, while assuring that Bulk-Power System operators and planners have the data they need for accurate disturbance monitoring and analysis. Likewise, regarding CAISO's request that the Commission direct NERC to consider requiring registered IBRs to provide additional data, we agree that such data collections may be warranted, and direct NERC to consider through its standards development process whether additional IBR data points (e.g., telemetry collections or other automated platform integrations) are needed to further enhance real-time visibility of Bulk-Power System operations."	The directive is addressed in the Reliability Standard PRC-028-1 which strikes a balance between recommendations from various NERC disturbance reports, comments received from industry including two inverter OEMs, available data recording technology, cost burden, reliability need, as well as use of collected data to aid with event analysis, model validation etc.
Paragraph 226: Although we are not directing NERC to include implementation dates in its informational filing and are leaving determination of the proposed effective dates to the standards development process, we are concerned that the lack of a time limit for implementation could allow identified issues to remain unresolved for a significant and indefinite period. Therefore, we emphasize that industry has been aware of and alerted to the need to address the impacts of IBRs on the Bulk-Power System since at least 2016. The number of events, NERC Alerts, reports, whitepapers, guidelines, and ongoing standards projects more than demonstrate the need for the expeditious implementation of new or modified Reliability Standards addressing IBR data sharing, data and model validation, planning and operational studies, and performance requirements. Thus, in that light, the	The implementation plan addresses Reliability Standard PRC-028-1 becoming effective on the first day of first calendar quarter from the effective date of Commission order approving the PRC-028-1. In addition, a phased-in approach is provided for Inverter-Based Resources that are in commercial operation before the effective date of this standard, with all Inverter-Based Resources in commercial operation before the effective date of this standard are required to fully comply with Requirements R1 through R7 by January 1, 2030. Recognizing circumstances beyond Entity's control (e.g., supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduling outages) which may

Commission will consider the justness and reasonableness of each new or modified Reliability Standard's implementation plan when it is submitted for Commission approval. Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date.	prevent the installation of Disturbance Monitoring Equipment per the time allowed at Inverter-Based Resources that are in commercial operation before the effective date of PRC-028-1, the implementation plan includes a process for requesting an extension from compliance dates. Inverter-Based Resources entering commercial operation after the effective date of PRC-028-1, Entities are required to comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or commercial operation date, whichever is later. For more details, see the PRC-028-1 Implementation Plan.

Exhibit E

Technical Rationale

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit E-1

Technical Rationale
Technical Rationale for PRC-002-5

Technical Rationale for Reliability Standard PRC-002-5

September 2024

PRC-002-5 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for Inverter-Based Resources to aid with event analysis, performance monitoring, and disturbance-based Inverter-Based Resource model validation. The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. Introducing Inverter-Based Resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for Inverter-Based Resources is created instead of revising the Reliability Standard PRC-002. To avoid any overlap between the Reliability Standards PRC-002 and PRC-028, BES Elements within Inverter-Based Resources meeting the criteria set by Inclusion I4 of the BES definition are excluded from Reliability Standard PRC-002. Example in Figure 1 is provided to clarify applicability of Reliability Standards PRC-002 and PRC-028. The Inverter-Based Resources in this example meets the criteria in inclusion I4 of the BES definition. The BES bus in substation Scott is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for BES Elements associated with the identified BES bus are per the Reliability Standard PRC-002 except for Elements associated with the Inverter-Based, i.e., circuit breaker 3. The SER, FR, and DDR data requirements for the Inverter-Based Resources are specified in the Reliability Standard PRC-028.

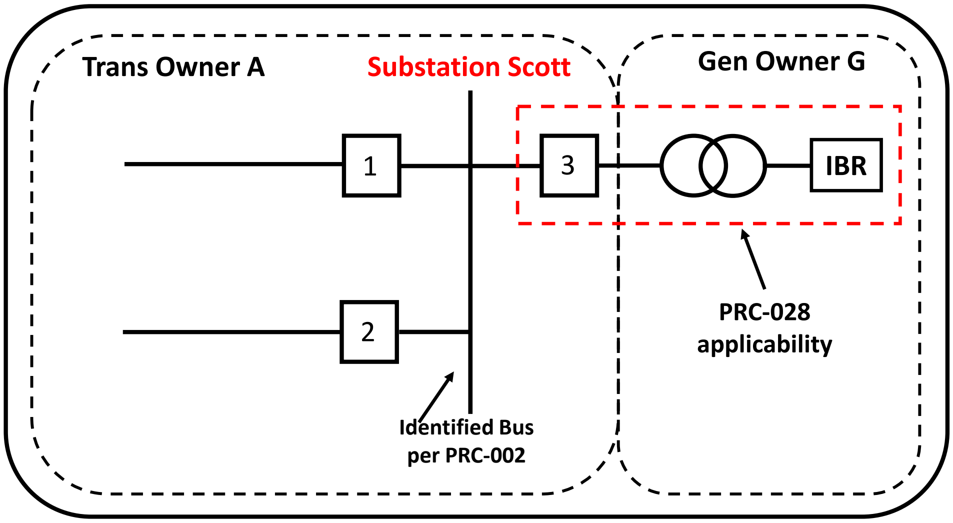

Figure 1: Example to Clarify Applicability of PRC-002 Versus PRC-028

Rationale for Requirement R1

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-5, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three-phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses, where SER and FR data is required, are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to

address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

5. Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three-phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.

7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B, and C are identified in Step 6. The maximum three phase short circuit MVA of buses A, B, and C is 1600 MVA, 1500 MVA, and 1550 MVA, respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three phase short circuit MVA of buses A, B, and C is 1550 MVA, 1675 MVA, and 1600 MVA, respectively. The bus B is the one with highest maximum three phase short circuit MVA now. The three phase short circuit MVA of bus B is within 15% of the three phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three phase short circuit MVA of buses A, B, and C is 1500 MVA, 1750 MVA, and 1650 MVA, respectively. The three phase short circuit MVA of bus B is greater than 15% of three phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g., synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g., combustion or steam turbine). As a result, this standard requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of “directly connected” BES Elements are notified. For the purposes of this standard, “directly connected” BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 2 and 3 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

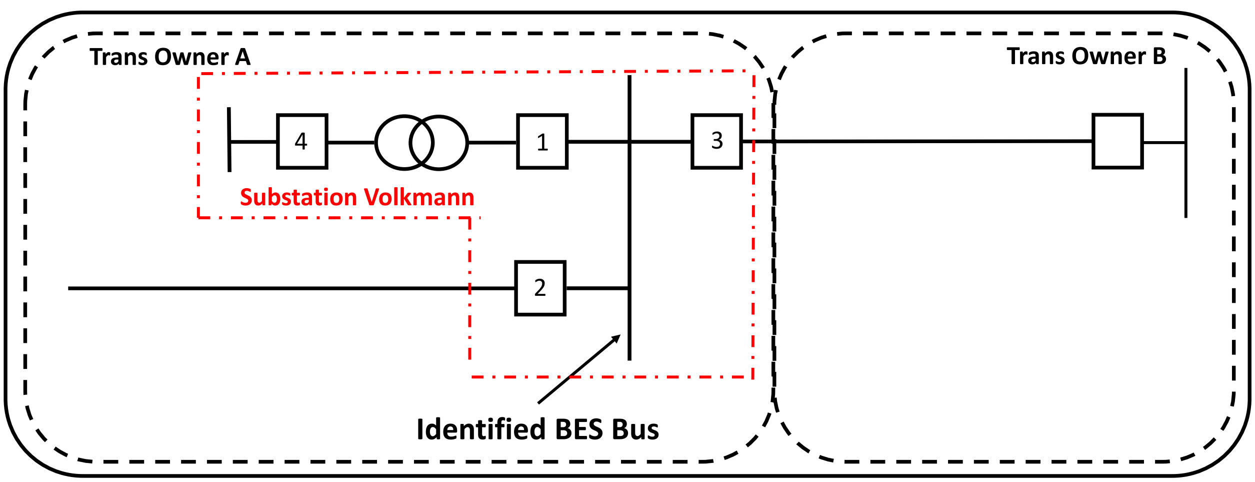

Figure 2: Straight Bus Configuration – Single Owner

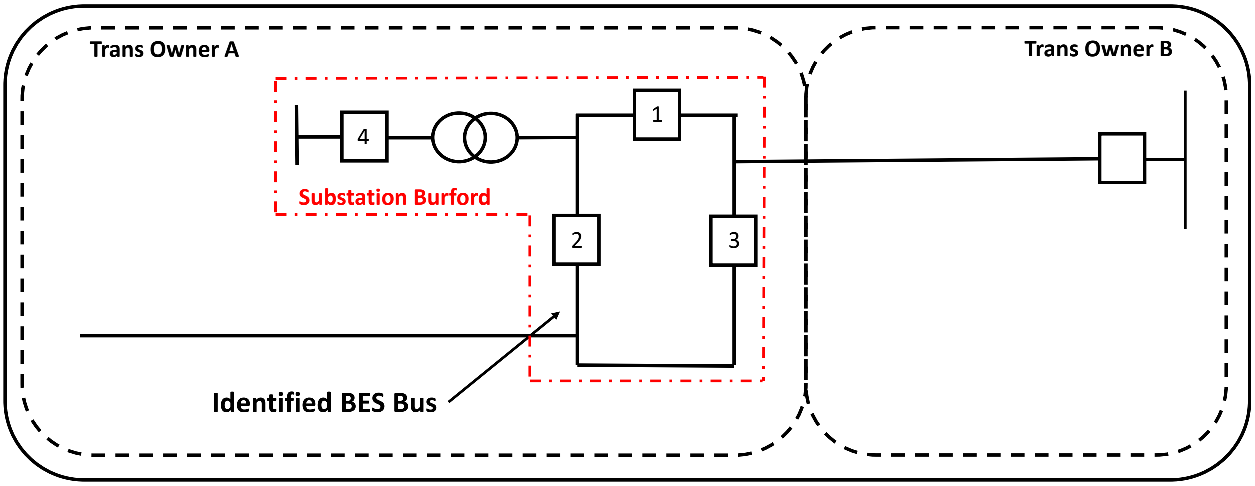

Figure 3: Ring Bus Configuration – Single Owner

Figures 4 and 5 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

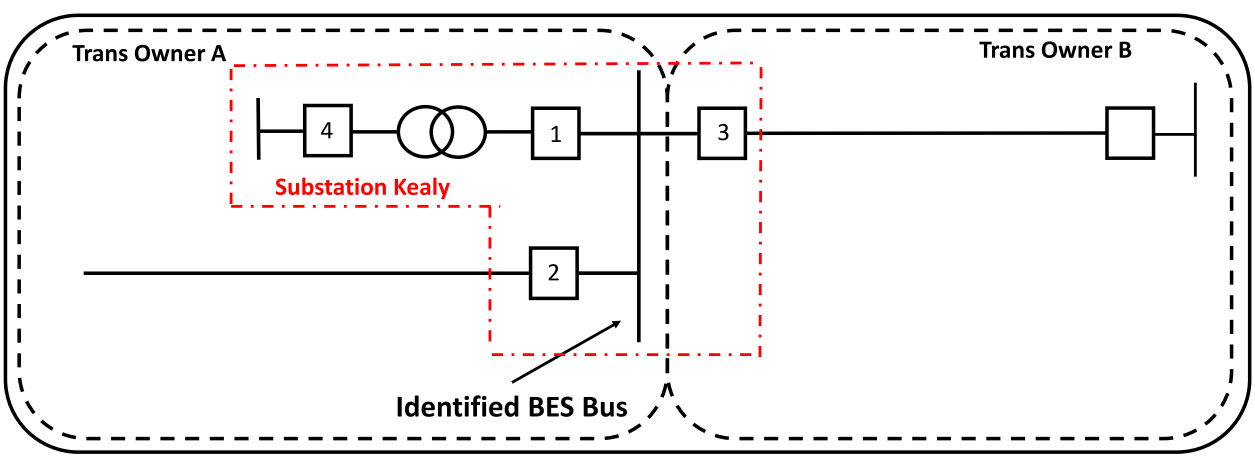

Figure 4: Straight Bus Configuration – Multiple Owners

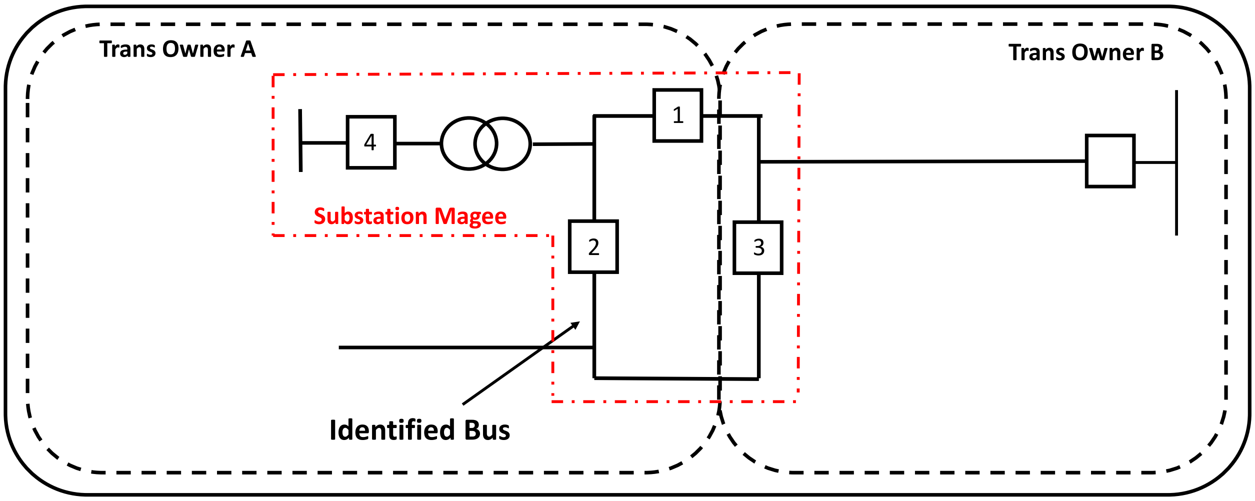

Figure 5: Ring Bus Configuration – Multiple Owners

For examples in Figures 4 and 5, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 6 shows an example with a generator interconnection. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

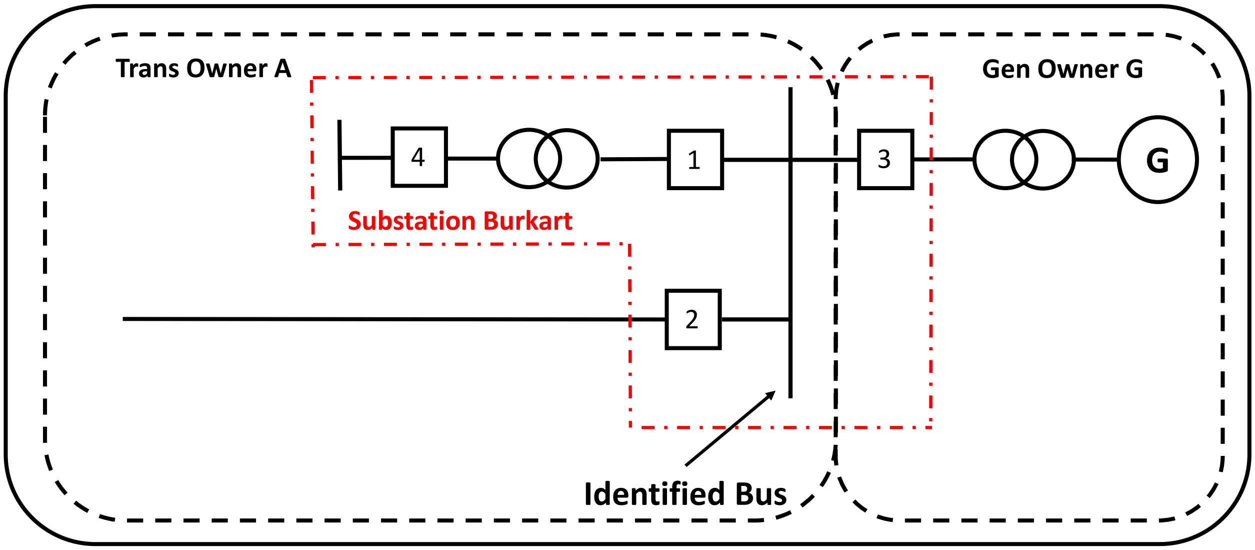

Figure 6: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 7, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

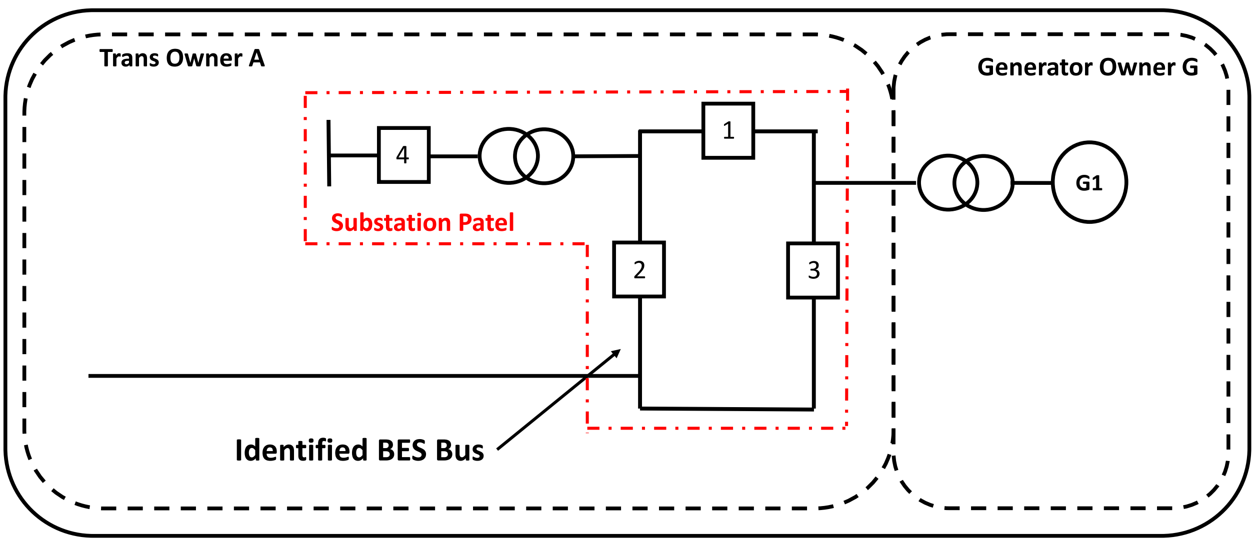

Figure 7: Generator Interconnection to Ring Bus

Figure 8 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical

bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

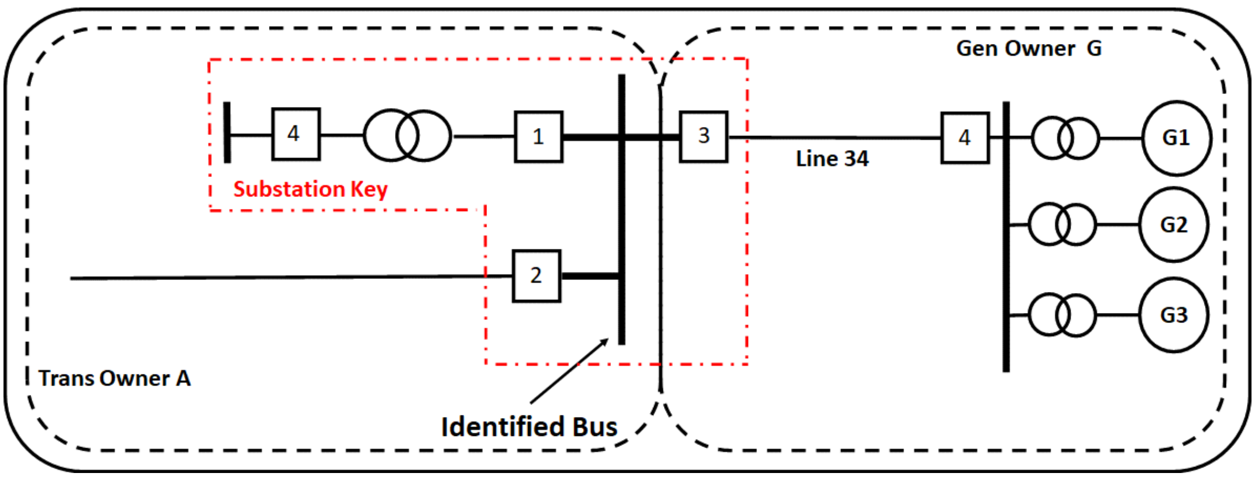

Figure 8: Generator Interconnection via Line 34

Figure 9 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3, and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

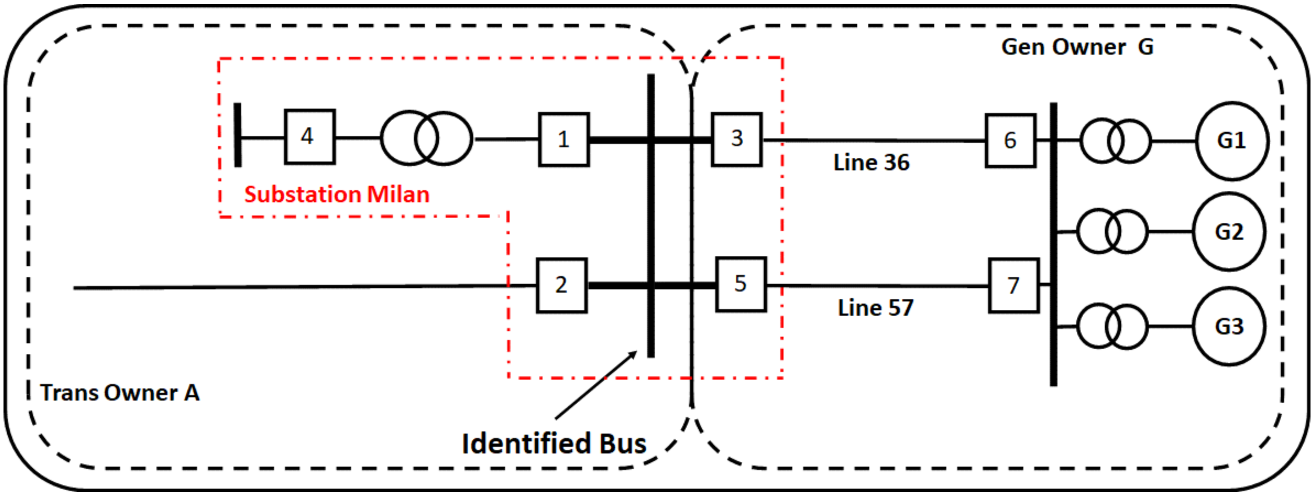

Figure 9: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification Transmission Owner B

Greetings,

In accordance with NERC Standard PRC-002-5, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Rationale for Requirement R2

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element directly connected to a BES bus. Change of state of circuit breaker position and time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position.

However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Examples in Figures 10, 11, and 12 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement R3

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g., residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads 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 are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements directly connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element directly connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities, it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

Examples in Figures 10, 11, and 12 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

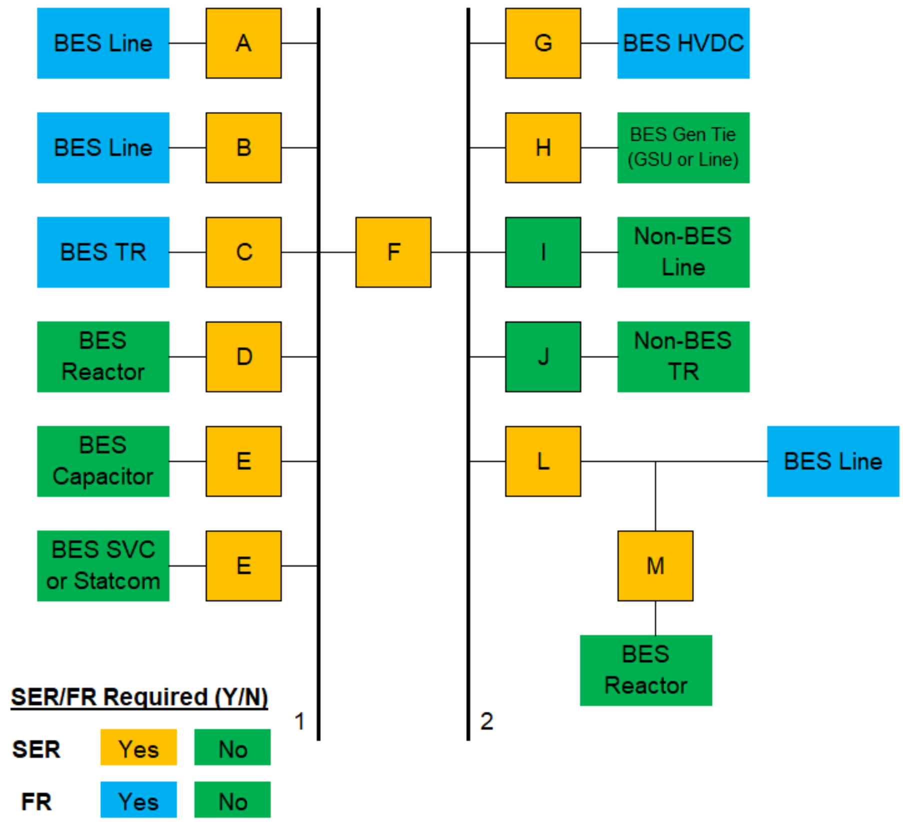

Figure 10: Straight BES Buses

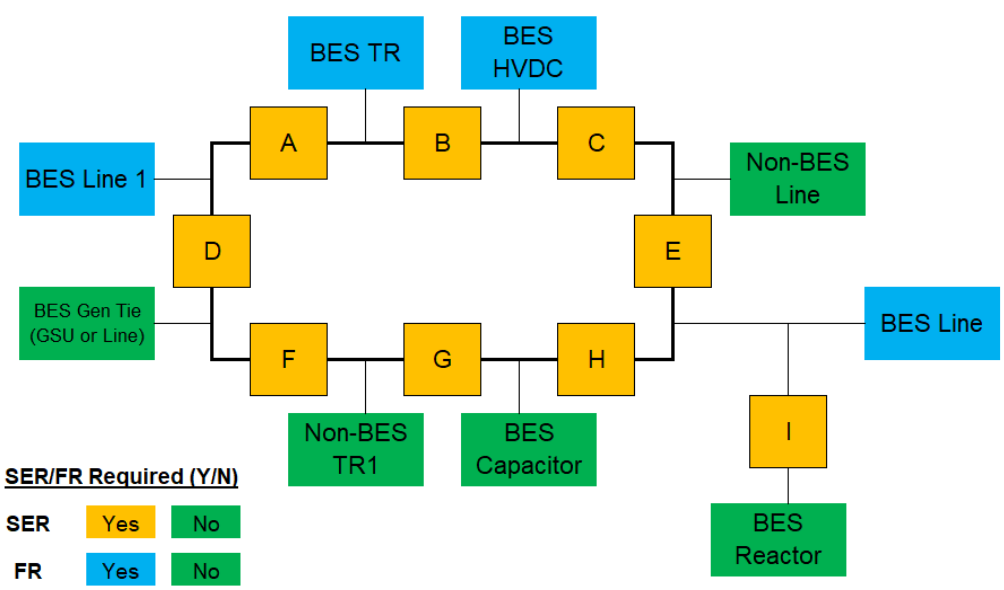

Figure 11: Ring BES Bus

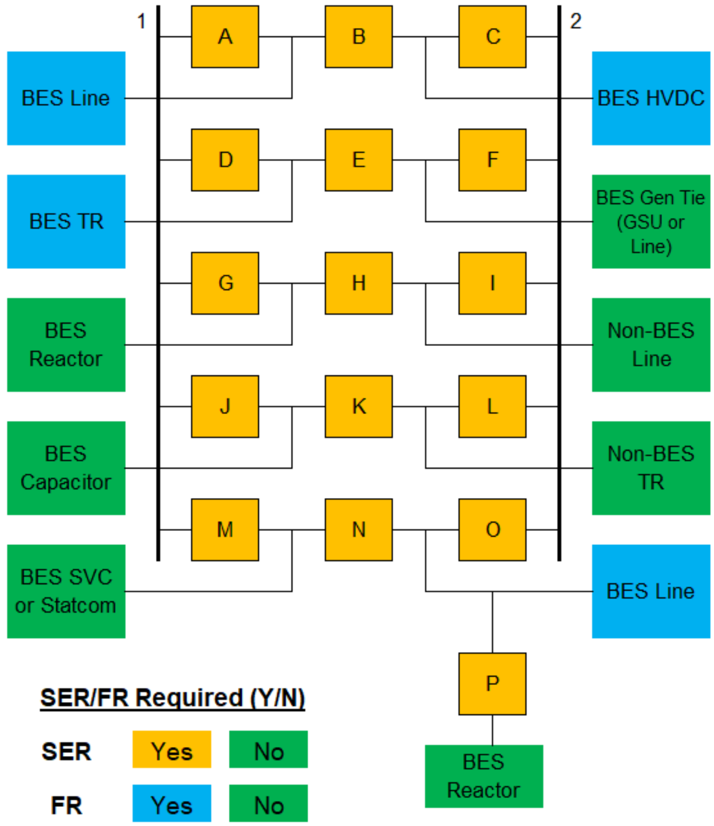

Figure 12: Breaker and Half BES Bus

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three

phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

<u>Voltage Recordings</u>
Voltages are to be recorded or accurately determined at applicable BES buses

Rationale for Requirement R4
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30- contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Rationale for Requirement R5
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for

specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data, as per Requirement R5, is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and

oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System-wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e., averages, means, and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e., units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e., the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes.

However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather, the drafting team believes this determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR, such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Rationale for Requirement R6

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral

voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three-phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Rationale for Requirement R7

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at eitherthe high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the ‘what’ of DDR, not the ‘how’. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again, it must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement R8

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post- contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Rationale for Requirement R9

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g., faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Rationale for Requirement R10

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment.

Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an

international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement R11

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improve timely analysis.

Providing the data within 30 calendar days (or the granted extension time), subject to Part 11.2, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10 calendar days inclusive of the day the data was recorded, i.e., a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data, or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.2 specifies the maximum time frame of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.1 specifies that the minimum time period of 10 calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies that the FR data shall be either in CSV format with appropriate headers or in electronic files that are formatted in conformance with IEEE C37.111. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange (COMTRADE) and is well established in the industry. Data submitted in a standard format helps with analysis of multiple submissions of data from many sources to provide a detailed analysis of a Power System Disturbance.

Requirement R11, Part 11.5 specifies that the DDR data shall be either in CSV format with appropriate headers or in electronic files that are formatted in conformance with IEEE C37.111. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R11, Part 11.6 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Rationale for Requirement R12

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90 calendar days (e.g., budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System.

Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90 calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Exhibit E-2

Technical Rationale

Technical Rationale for PRC-028-1

Technical Rationale for Reliability Standard PRC-028-1

September 2024

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

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for Inverter-Based Resources to aid with event analysis, performance monitoring, and disturbance-based Inverter-Based Resource model validation. These disturbance reports are recommended to install disturbance monitoring equipment (DME) at wind and solar photovoltaic (PV) resources to ensure adequate data is available for event analysis, performance monitoring, and validating Inverter-Based Resource models. The recommendation included plant-level high resolution oscillography data, plant SCADA data with a resolution of one second, and inverter level of sequence of events recording data that include all fault codes and high resolution oscillography data. In a first version of this standard, only SER data at inverter level data is required. For the purposes of this standard, the inverter, converter, wind turbine generator, or high voltage direct current converter connecting generating resource to alternating current Transmission network is referred to as an IBR unit.

The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. The recent disturbance analyses of events involving inverter-bases resources (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have demonstrated that Inverter-Based Resource's response to a normally cleared few cycle fault is undesirable and poses risk to system reliability. All these disturbance analyses have identified that Inverter-Based Resources involved did not have sufficient monitoring data to understand the plants' responses. The initiating event, e.g., a normally cleared transmission fault, was not a large-scale system disturbance; however, Inverter-Based Resource's undesirable response due to a system fault resulted in a larger system disturbance. Adequate monitoring data is required to understand Inverter-Based Resource's performance. Most of the Inverter-Based Resources involved in these disturbances did not have and were not required to have adequate disturbance monitoring data. The lack of disturbance monitoring data available from these facilities led to difficulty in adequately assessing the events. Introducing Inverter-Based Resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for Inverter-Based Resources is created instead of revising the Reliability Standard PRC-002.

The Generator Owners, as applicable, will have the responsibility for ensuring that adequate data is available for applicable Elements at the applicable Inverter-Based Resources. This standard requires that sequence of events recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data is available from the applicable Inverter-Based Resources.

Rationale for Applicability Section

Functional Entities

The functional entity that is responsible for implementing disturbance monitoring equipment and collecting recording data is Generator Owner.

Applicable Facilities

The BES Inverter-Based Resources and Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV, are in the scope of this standard.

Order No. 901 directed NERC to develop Reliability Standards "to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment." Order No. 901 at P 85. FERC continued, "We further agree with the findings in NERC reports (e.g., a lack of high-speed data captured at the IBR or plant-level controller and low-resolution time stamping of inverter sequence of event recorder information has hindered event analysis) and direct NERC through its standard development process to address these findings."

In distinguishing among the different types of IBRs and their registration status that must be covered by the standards, FERC stated: "Where necessary to describe our directives, however, we differentiate between IBRs registered with NERC (or which will be registered pursuant to the Commission's directives in Registration of Inverter-based Resources, 181 FERC ¶ 61,124 (2022) (IBR Registration Order)) and therefore subject to the Reliability Standards (i.e., registered IBR), IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards (i.e., unregistered IBRs), and IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk Power System (i.e., IBR-DER)." Order No. 901 at n. 14.

In proposed PRC-028-1, the standard drafting team includes both categories of generation that would be registered under proposed changes to NERC Rules of Procedure consistent with Order No. 901. In February 2024, the NERC Board of Trustees approved revisions to the Rules of Procedure to expand the Generator Owners and Generator Operators registered with NERC for compliance purposes. In addition to owners and operators of generating Facilities, NERC will register owners and operators of sub-BES IBRs meeting the following criteria: non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. On June 27, 2024, FERC issued an order approving NERC's proposed revisions to its Rules of Procedure, subject to NERC submitting a compliance filing, under section 215 of the Federal Power Act.

The following Elements associated with Inverter-Based Resources noted above are in the scope of this standard:

- Circuit breaker(s) (or interrupting devices)
- Main power transformer(s)
- Collector bus
- Shunt static or dynamic reactive device(s)[1], including any filter banks,
- AC-DC and DC-AC converters, if any, in case of VSC HVDC line with a dedicated connection to Inverter-Based Resource

The following examples are provided to clarify applicability of the PRC-028 standard.

Example 1: Applicability of PRC-028

Figure 1 shows a typical single line diagram of an Inverter-Based Resource. The Inverter-Based Resource is connected to the transmission system via a short tie-line. This Inverter-Based Resource is equipped with a dynamic reactive device (e.g., synchronous condenser, static VAR compensator etc.) connected to the collector bus.

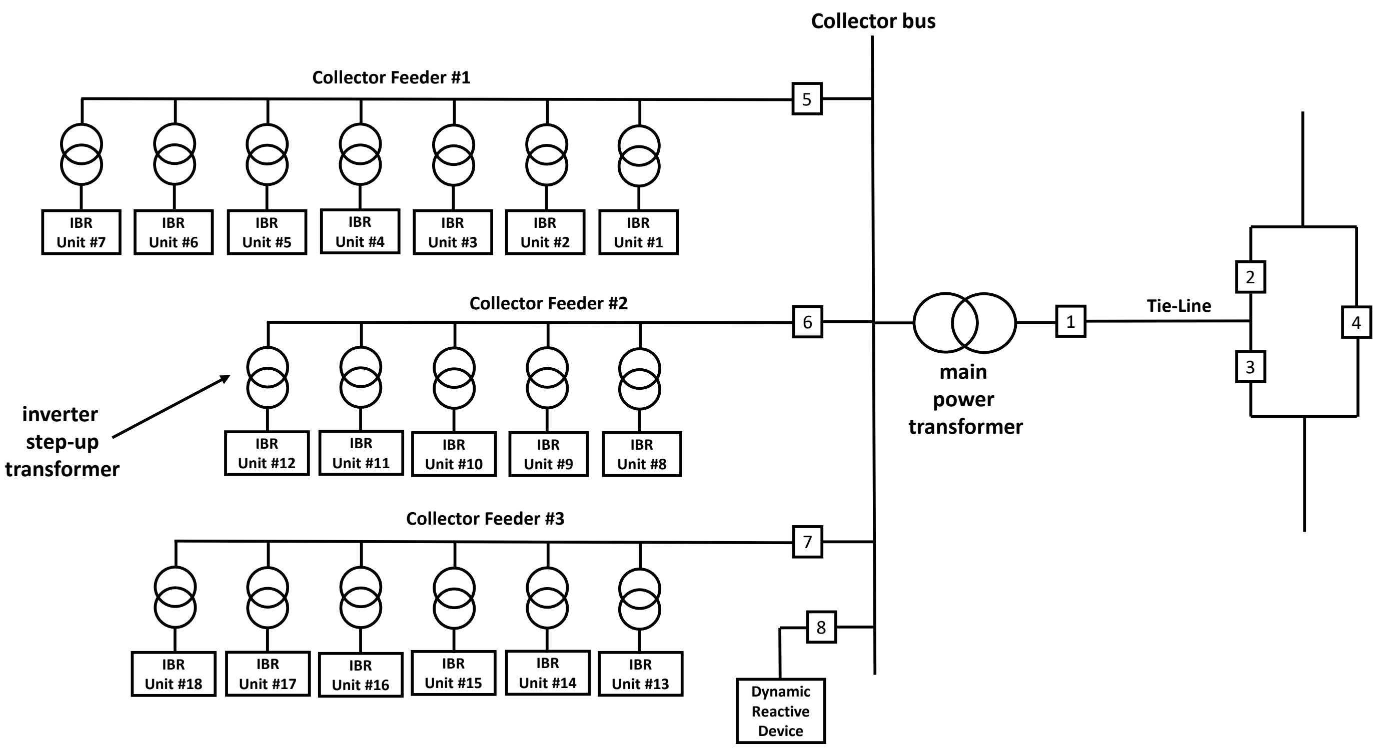

Figure 1: Typical Inverter-Based Resource Single Line Diagram

[1] Synchronous condensers when installed within the Inverter-Based Resource are considered shunt dynamic reactive devices.

SER Data: The SER data is required for circuit breakers 1, 5, 6, 7, and 8. Circuit breaker 1 is associated with the main power transformer. Circuit breakers 5, 6, 7, and 8 are associated with the collector bus. The SER data from all IBR units is required.

FR Data: The FR data is required from high side terminals of the main power transformer. In this example, the Inverter-Based Resource consists of only one main power transformer. If the Inverter-Based Resource consists of more than one main power transformer, then FR data for each main power transformer is required. As the Inverter-Based Resource is equipped with the dynamic reactive device, the FR data for it is also required. The FR data from collector feeder circuit breakers 5, 6, and 7 is also required.

DDR Data: The DDR data is required from high side terminals of the main power transformer. If the Inverter-Based Resource consists of more than one main power transformer, then DDR data for each main power transformer is required.

Example 2: Applicability of PRC-028 (Facility with two collector buses and main power transformers)

Figure 2 shows a single line diagram of an Inverter-Based Resource with two collector buses and main power transformers. The Inverter-Based Resource is connected to the transmission system via a short tie-line. The collector feeders #1 and #2 are connected to collector bus #1. The collector feeders #3 and #4 are connected to collector bus #2.

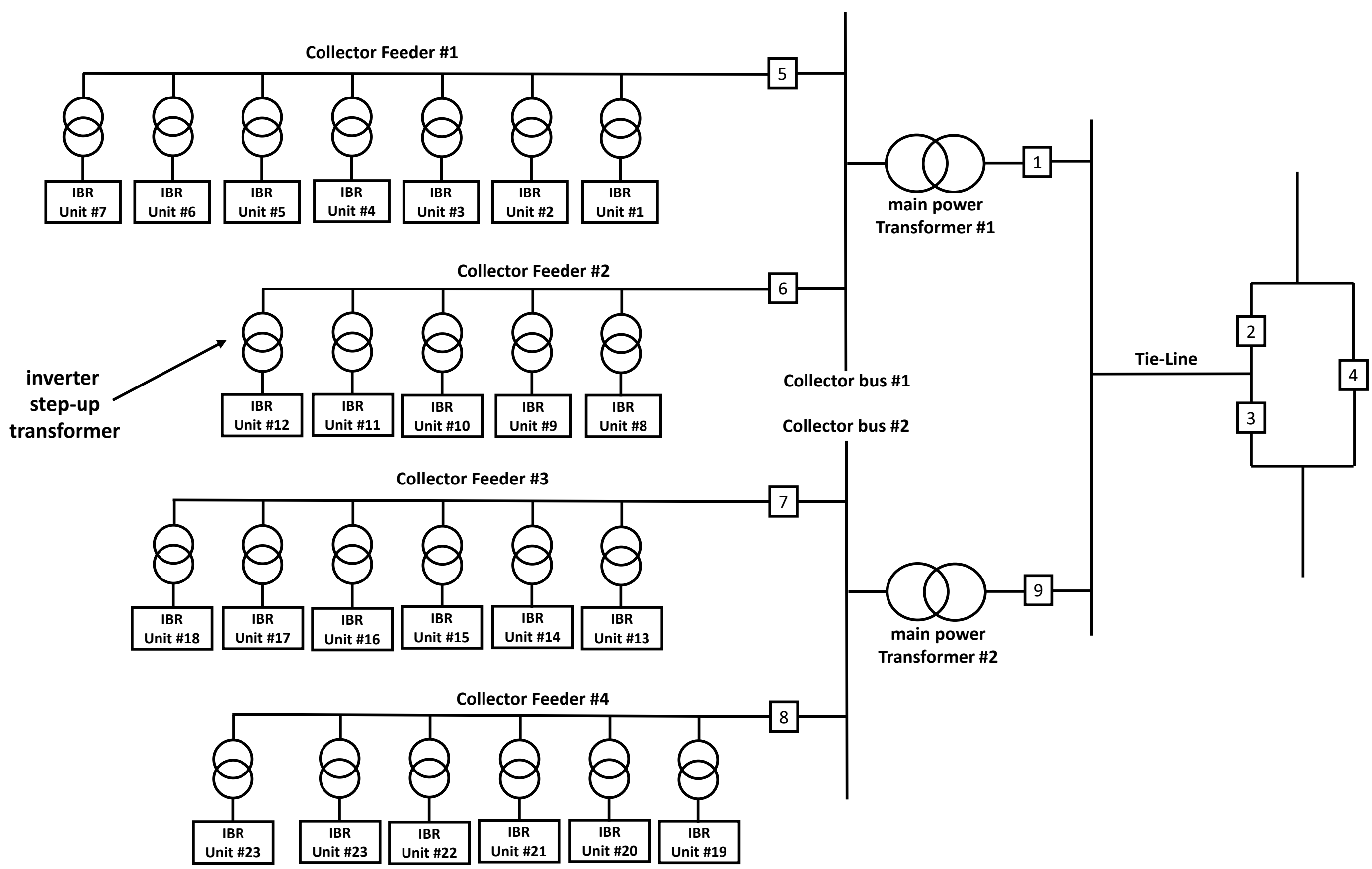

Figure 2: Typical Inverter-Based Resource with two collector buses and main power transformers

SER Data: The SER data is required for circuit breakers 1, 5, 6, 7, 8, and 9. Circuit breakers 1 and 9 are associated with main power transformers. Circuit breakers 5, 6, 7, and 8 are associated with collector buses #1 and #2. The SER data from all IBR units is required.

FR Data: The FR data is required from high side terminals of both main power transformers. The FR data from collector feeder circuit breakers 5, 6, 7, and 8 is also required.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 3: Applicability of PRC-028 (VSC HVDC system with a dedicated connection to Inverter-Based Resources)

Figure 3 shows an example of dedicated VSC HVDC system connecting the Inverter-Based Resource[2]. Transformers on both sides of the HVDC system are considered main power transformer.

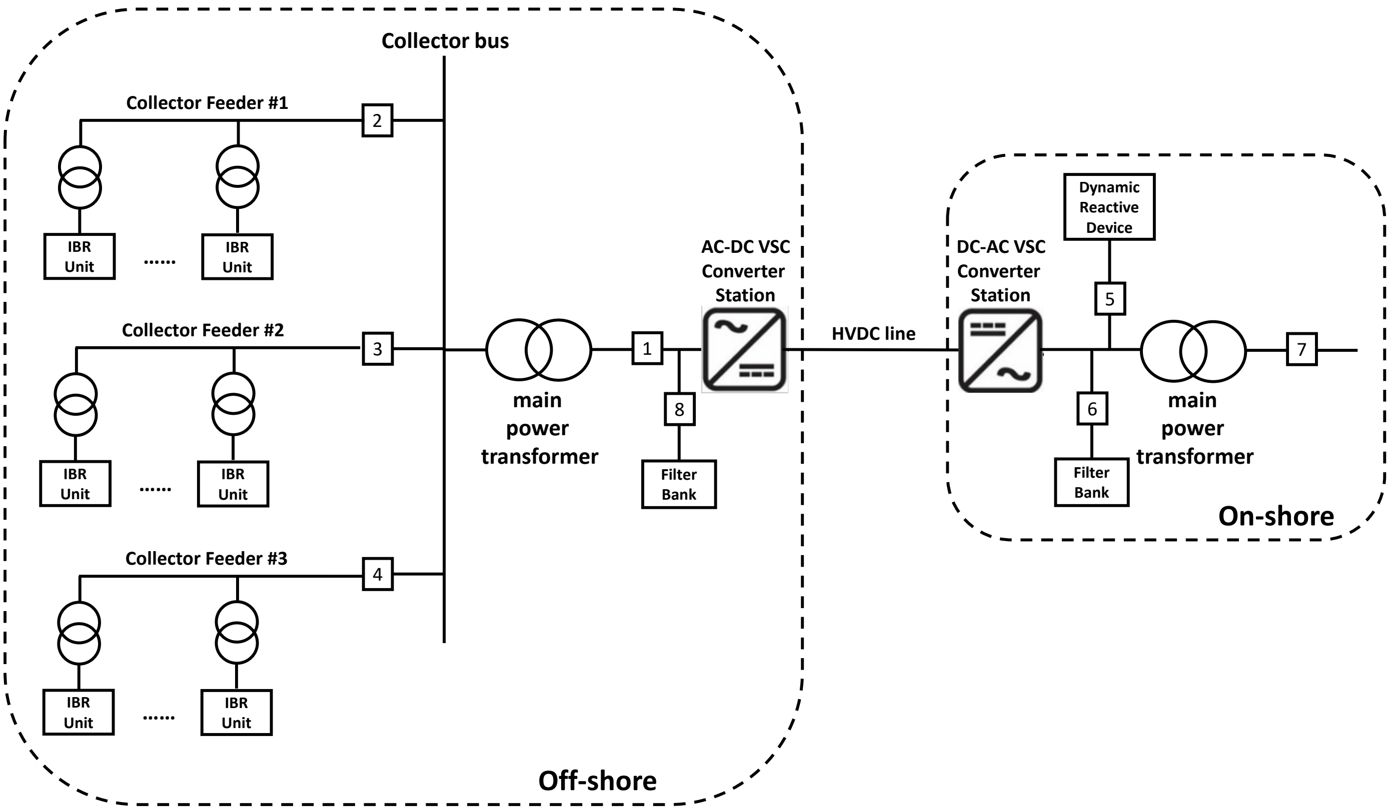

Figure 3: Typical Inverter-Based Resource connected via dedicated VSC HVDC

[2] Refer to Technical Rationale Project 2020-06 Verification of Models and Data for Generators Inverter-based Resource Definition available at: https://www.nerc.com/pa/Stand/Project_2020_06_Verifications_of_Models_and_Data_f/2020-06_IBR_Definition_Technical_Rationale_Clean_07122024.pdf.

SER Data: The SER data is required for circuit breakers 1, 2, 3, 4, 5, 6, 7, and 8. Circuit breakers 1 and 7 are associated with main power transformers. Circuit breakers 2, 3, and 4 are associated with the collector bus. Circuit breakers 6 and 8 are associated with filter banks and circuit breaker 5 is associated with shunt dynamic reactive device. The SER data from all IBR units is required.

FR Data: The FR data is required from high side terminals of both main power transformers. The FR data from collector feeder circuit breakers 2, 3, and 4 is also required.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 4: Applicability of PRC-002 versus PRC-028

Figure 4 shows an example of Inverter-Based Resource interconnection to the transmission system via Line 34. The BES bus in substation Wu is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for the identified BES bus are per the requirements in the Reliability Standard PRC-002. The Reliability Standard PRC-028 is applicable to the Inverter-Based Resource.

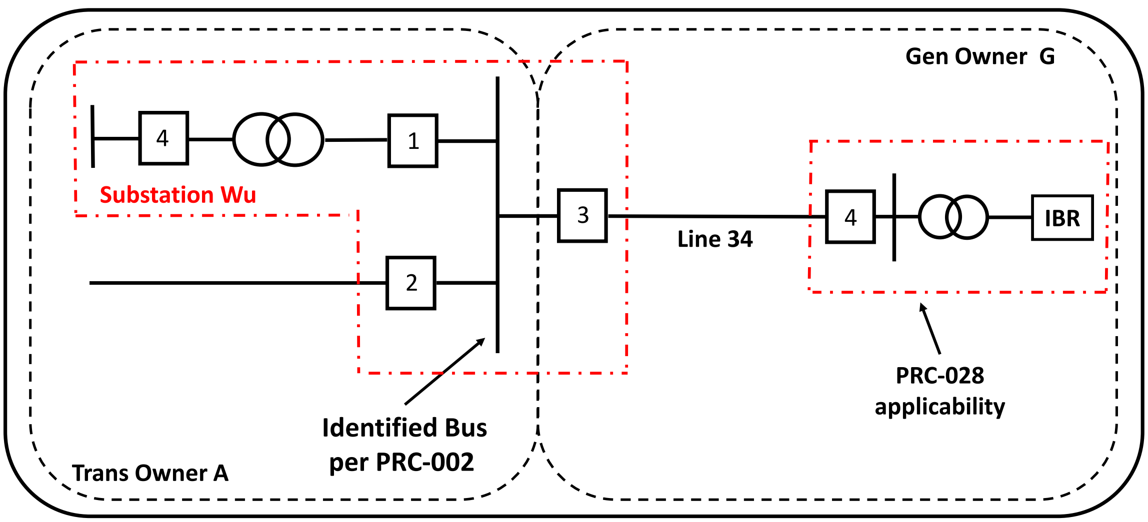

Figure 4: Inverter-Based Resource Interconnection – Applicability of PRC-002 versus PRC-028

Rationale for Requirement R1

The standard is required to capture SER data from circuit breakers within the Inverter-Based Resource associated with:

- Main power transformer(s)
- Collector bus(es), including collector feeder[3] breakers
- Shunt static or dynamic reactive device(s), including any filter banks
- AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to Inverter-Based Resources.

[3] Collector feeder is a feeder that connects one or more IBR unit step-up transformer with the collector bus.

The standard also requires capturing SER data from all IBR units. However, it is recognized that for IBR units in commercial operation before the effective date of this standard, IBR units may not be capable to capture SER data. If IBR unit is in commercial operation before the effective date of this standard and not capable to capture SER data then SER data is not required. The SER data required from IBR units, when triggered by ride-through operation or tripping, are as follows: all fault codes and alarms, high and low voltage/frequency ride-through mode status. Note that fault codes, alarms, ride-through mode status, etc., in IBR units are not standardized across all manufacturers. Hence, the standard does not specify specific fault codes and alarms. The requirement is to record any fault code or alarm that is generated by *IBR unit tripping*. The recording of fault codes and alarms may help understand reasons for which IBR unit tripped and may help determine if it is correct or incorrect operation. Some of the typical protective functions[4] utilized within IBR unit, that may generate fault code or alarm, are as follows:

- Open phase detection
- ac and dc overcurrent protection
- ac undervoltage and overvoltage protection
- dc undervoltage protection
- Underfrequency and overfrequency protection
- ROCOF protection
- Loss of synchronization
- Unintentional islanding protection
- Reverse current protection
- dc ground fault protection
- ac ground fault protection
- Negative sequence current protection

IBR units typically enter a ride-through operation when voltage or frequency deviates beyond certain thresholds. The threshold beyond which IBR unit enters a ride-through operation may vary based on manufacturer, IBR plant’s size, location, etc. The IBR unit is typically configured to record a change in status whenever it enters or exits a voltage or frequency ride-through operation. The standard simply requires recording of this change in status where there exists capability for the IBR unit. Note that entering momentary cessation is not considered ride-through but meets the same recording trigger requirements as ride-through.

It is not the intent of this standard to require addition of any monitoring equipment to record IBR unit SER data. The new IBR units are capable to record required SER data. In case of IBR units in commercial operation before the effective date of this standard, the recording of SER data is required only if IBR unit has a capability to do so.

[4] IBR unit may not utilize all these protective functions.

It is recognized that the manufacturer of an IBR unit in commercial operation before the effective date of this standard may be out of business, acquired by, or merged with another manufacturer. In such cases, if the entity is not able to determine capability of IBR unit to record the required SER data, the SER data is not required. Documentation should be retained to demonstrate that entity is unable to determine IBR unit recording capability from available manufacturer data either from an original manufacturer or from an acquiring manufacturer.

Change of state of circuit breaker position and IBR unit SER data, time stamped according to Requirement R7 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of Inverter-Based Resource's response during a power System disturbance. Analyses of system disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations helps determine the interruption of flows during the disturbances.

Rationale for Requirement R2

The intent is to capture sufficient FR data for Elements at each Inverter-Based Resource to analyze the overall response of the Inverter-Based Resource to a system disturbance. Analyses of disturbances involving widespread reduction of power output from Inverter-Based Resources in recent years has shown that expansion of monitoring at Inverter-Based Resource sites is necessary. The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g., residual or neutral current if the phase currents are directly measured).

The FR data captured from IBR units helps in understanding individual IBR unit's response during system disturbances. However, in lieu of requiring FR data from IBR units, standard requires FR data from collector feeder breakers. The FR data captured from collector feeder breakers provides information about collective response of IBR units on a given collector feeder during system disturbances.

The plant level FR measurements, i.e., measured on high-side terminals of the main power transformer, specified in Requirement R2, Part 2.1 provide data at the Inverter-Based Resource interconnection to the bulk power system. To cover all possible fault types, phase-to-neutral voltage recording for each phase is required to be determinable. Each phase current and residual current are required to distinguish between phase faults and ground faults. This data also facilitates determination of the fault location and cause of relay operation. The measurements of active and reactive power provide data on the overall generating facility's response to the system disturbance.

In some cases, the dynamic reactive device is used within the Inverter-Based Resource and often connected to medium voltage collector bus. Regardless of where dynamic reactive device is connected, the output of it during system disturbances is important to understand overall performance of the plant during a disturbance. The measured or determined electrical quantities for dynamic reactive device are same as those specified to be measured/determined from high-side of main power transformer.

<u>Recording of Electrical Quantities</u>

For effective fault analysis, it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation. FR also shows generator output response to a system disturbance.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120 degrees, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current Ir, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable Elements as outlined in Requirement R2.

Rationale for Requirement R3

Time stamped pre- and post-trigger FR data aid in the analysis of power system operations and determination if operations were as intended.

The “Odessa Disturbance” report from September 2021 recommended high resolution oscillography data at the point of interconnection. The minimum recording rate of 64 samples per cycle is specified recognizing state-of-the-art for DME including storage any storage capability limitations and provides sufficient data to recreate accurate response of the Inverter-Based Resource to system disturbances.

Pre- and post-trigger fault data along with the SER data, all time stamped to a common clock, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Additionally, Inverter-Based Resources employ fast acting control systems (with built in protection functions) dictating Inverter-Based Resource’s response to system disturbance. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles. To capture the full response of Inverter-Based Resource spread over a large geographic area, a 2 second total minimum record length synchronized to a common clock is necessary for FR data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data but are not capable of providing fault data in a single record with 120 continuous cycles total.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R3, Part 3.1.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R3, sub-Part 3.1.3.2 specifies a phase overvoltage or undervoltage trigger during voltage ride-through events.

The triggers specified in Requirement R3, Part 3.3 for dynamic reactive device FR data are similar to ones specified in Requirement R3, Part 3.1 for plant level FR data measured or determined on high-side of the main power transformer.

Rationale for Requirement R4

Large scale system disturbances generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and Inverter-Based Resource's response to large scale system disturbances. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event. The state-of-the-art DDR equipment is capable of continuous recording.

DDR data contains the dynamic response of the Inverter-Based Resource to a system disturbance and is used for analyzing complex power system events. This recording is typically used to capture short-term and long-term disturbances. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

DDR is used to measure transient response to system disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage and current from the same phase or positive sequence for each applicable main power transformer for analysis. It is also sufficient to provide a single frequency for any of the provided voltages since all main power transformers within an Inverter-Based Resource are at the same frequency. Recording of all three phases of voltage/current is not required, although this may be used to compute and record the positive sequence value(s). The electrical quantities for Real Power and Reactive Power on a three-phase basis can be measured/recorded or determined (calculated, derived, etc.).

The data requirements for PRC-028-1 are based on a system configuration assuming all normally closed circuit breakers on a BES bus are closed.

A crucial part of disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary to have DDR on high-side of the main power transformer(s) measuring the specified electrical quantities to adequately capture Inverter-Based Resource's response.

The Requirement R4, Part 4.1 requires either one phase-to-neutral or positive sequence voltage. However, the phase-to-phase voltage recording is acceptable. Since the BES operates under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Rationale for Requirement R5

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltages and frequency. The input sampling rate specified is same as one specified in the Reliability Standard PRC-002.

An output recording rate of electrical quantities of at least 60 times per second refers to the recording rate of the device. Recorded measurements of at least 60 times per second provide adequate recording speed to monitor the Inverter-Based Resource's response during power system disturbances. Since control system associated with Inverter-Based Resources is fast acting, higher frequency recording is necessary to accurately reconstruct events. An output recording rate of 60 times per second provides this higher frequency recording while not greatly increasing data storage requirements.

Rationale for Requirement R6

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 1 millisecond accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 1 millisecond accuracy will suffice with respect to providing time synchronized data. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. Note that the recently published IEEE Std 2800 requires the DME recording plant level data be synchronized to the clock with accuracy of ± 1 microsecond accuracy; however, the accuracy requirement is set to ± 1 millisecond to strike a balance between need of accuracy and practical limitations of equipment necessary to achieve the stated accuracy. Recognizing challenges with distributing synchronizing clock signal to all IBR units with the Inverter-Based Resource, the IBR units (for capturing of SER data) are required to have synchronized device clock accuracy within ± 100 milliseconds of UTC. Note that higher tolerance in clock accuracy allows for larger deviation from a synchronized signal. The clock accuracy required for IBR plant level data is more stringent than IBR unit level data.

The Inverter-Based Resources, which are not affected by inertial time constants, make changes in power production very rapidly. To understand and analyze control decisions during system disturbances and the reasons behind them over dozens of plants requires a high level of accurate time synchronization. The following provide some examples of Inverter-Based Resource's fast response:

- Typical 90% response to a three-phase fault is < 40 ms.

- Central power plant controllers issue updated commands in as little as 40 ms upon detection of change in system conditions.
- Standard closed loop voltage control response can be <200 ms.
- Instantaneous Inverter protective trip decisions such as AC or DC overvoltage or reverse DC current can be made in less than 10 ms.

Rationale for Requirement R7
Requirement R7, Part 7.1 specifies a minimum time period of 20 calendar days inclusive of the day the data was recorded for which the data is to be retrievable. Data hold requests are usually initiated the same or next day following a major event, however, it takes a longer time to determine which data from which generating facility needs to be retrieved for event analysis. A 20 calendar day time period provides enough time for communication between various Entities regarding the event and need for data retrieval from DME at various generating facilities. The requestor of data has to be aware of 20 calendar day retrievability limit to ensure timely data hold requests. Requiring data retention for a longer period of time is expensive and unnecessary.

With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 20 days. To clarify the 20 calendar day time frame, let's assume that event occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 20 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 21, that is outside the 20 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER, FR and DDR data for generating facilities as per the applicability. To facilitate the analysis of system disturbances, it is important that the data is provided to the requestor within a reasonable time. Providing the data within 15 calendar days (or the granted extension time), subject to Requirement R7, Part 7.2, allows for reasonable time to collect the data and perform any necessary computations or formatting. An entity may request an extension of the 15 calendar days submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Disturbance analysis includes reviewing data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improve timely analysis. The formatting and naming convention requirements for SER, FR, and DDR are consistent with same requirements in the Reliability Standard PRC-002.

<u>**SER data:**</u> Requirement R7, Part 7.3 specifies a simple ASCII Comma Separated Value (CSV) format according to Attachment 1. It is necessary to establish a standard format as it allows data submitted by one entity or facility to be incorporated with same data provided by other entities or facilities to develop a detailed sequence of events timeline of a power system disturbance.

FR data: Requirement R7, Part 7.4 specifies either CSV format with appropriate headers or the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the FR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources.

DDR data: Requirement R7, Part 7.5 specifies either CSV format with appropriate headers or the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the DDR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources.

The 2013 revision of the IEEE C37.111 includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R7, Part 7.6 specifies the IEEE C37.232 Standard for Common Format for Naming Time Sequence Data Files (COMNAME) format for naming the SER, FR, and DDR data files. The lack of a common naming practice seriously hinders the event analysis and investigation process.

Rationale for Requirement R8

The standard requires that Entity restore the recording capability for SER, FR, or DDR data within 90 calendar days of the discovery of a failure. The 90 calendar day time period permitted in this requirement strikes a balance between reasonable time needed to restore capability while ensuring that recording capability is not out of service for an extended duration. If the recording capability cannot be restored within 90 calendar days due to limitations such as budget cycle, service crews, vendors, needed outages, etc., the entity is required to submit a Corrective Action Plan for restoring the recording capability to the Regional Entity and implement it. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored Element does not constitute a failure of the disturbance monitoring capability.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit F

Analysis of Violation Risk Factors and Violation Severity Levels

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit F-1

Analysis of Violation Risk Factors and Violation Severity Levels
PRC-002-5

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Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-002-5)

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 PRC-002-5. 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.

VRF Justification for PRC-002-5, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justifications for PRC-002-5, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

VSL Justifications for PRC-002-5, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R2

The VRF did not change from the previously FERC approved PRC-002-4Reliability Standard.

VSL Justification for PRC-002-5, Requirement R2

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R3

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R3

VSLs for PRC-002-5, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-002-5, Requirement R3	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R4

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R4

VSLs for PRC-002-5, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.

VSL Justifications for PRC-002-5, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R5
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R6

VSLs for PRC-002-5, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities,	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities,	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities,	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total

which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-002-5, Requirement R6	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justification for PRC-002-5, Requirement R7

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R7

VSLs for PRC-002-5, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-002-5, Requirement R7	
Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R8

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R8

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R9

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R9

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R10

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R10

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R11

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R11

VSLs for PRC-002-5, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide

than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-002-5, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R11	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit F-2

Analysis of Violation Risk Factors and Violation Severity Levels
PRC-028-1

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-028-1)

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 PRC-028-1. 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-028-1

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the circuit breaker(s) identified in Requirement R1.

VSL Justifications for PRC-028-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R1	
Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 80 percent, but less than 100	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 70 percent, but less than or	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 60 percent, but less than or	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers less than or equal to 60 percent of the

percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-028-1, Requirement R2	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R3	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
	capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R4	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
Guideline 2- Consistency within a Reliability Standard	and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

VSL Justifications for PRC-028-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 15 calendar days, but less than or equal to 25 calendar days after the request, unless an	The Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 25 calendar days, but less than or equal to 35 calendar days after the request, unless an	The Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 35 calendar days, but less than or equal to 45 calendar days after the request, unless an	The Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 45 calendar days after the request, unless an extension was granted by the requestor.

extension was granted by the requestor. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	extension was granted by the requestor. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	extension was granted by the requestor. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Generator Owner as directed by Requirement R8 submitted a	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and failed to provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR The Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90

		Corrective Action Plan to the Regional Entity but failed to implement it.	calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-028-1, Requirement R8	
Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit G

Summary of Development History
and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standards PRC-028-1 and PRC-002-5 developed under Project 2021-04 Modifications to PRC-002-2 Disturbance Monitoring - Phase II. Phase I of the project was completed in 2022 with the development of PRC-002-4 addressing the Glencoe Light Standard Authorization Request ("SAR").[1]

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.[2] The technical expertise of the ERO is derived from the drafting team ("DT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[3] For this project, the DT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2021-04 Standard DT members is included in **Exhibit H**.

II. Standard Development History

A. Standard Authorization Request Development

Project 2021-04 proceeded in two phases, tied to each of two SARs submitted regarding Reliability Standard PRC-002-2. The Glencoe Light SAR addressing clarifications to certain notification requirements relative to Fault Recording ("FR") data proceeded as phase one and resulted in the development of PRC-002-4 in 2022. Subsequent work under Project 2021-04 proceeded to engage with the second SAR, the result of work by the NERC's Inverter-based Resource Performance Task Force ("IRPTF").

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1 Exhibit G at Item 1 and 13.

2 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2024).

3 The NERC *Standard Processes Manual* is available at https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_3A_SPM_Clean_Mar2019.pdf.

The IRPTF performed a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements relative to the incorporation of increasing Inverter-based Resources ("IBR"). The IRPTF analysis, "IRPTF Review of NERC Reliability Standards White Paper," was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed, and it submitted a SAR for consideration by the Standards Committee.

At its January 19, 2022 meeting, the Standards Committee accepted both the Glencoe Light and IRPTF SARs, authorized drafting revisions to the standards, and appointed the SAR Drafting Team as the Standard Drafting Team ("SDT"). [4]

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

On July 19, 2023, the Standards Committee authorized initial posting of the proposed Reliability Standards PRC-002-5, PRC-028-1, the associated Implementation Plan, Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"), and other associated documents for a 45-day formal comment period from August 1 – September 14, 2023, with a parallel initial ballot and non-binding poll held during the last 10 days of the comment period from September 5 – 14, 2023.[5] There were 71 sets of responses, including comments from approximately 182 different individuals and approximately 121 companies, representing all 10 industry segments.[6] The following table

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[4] NERC, *Minutes – Standards Committee Conference Call Jan. 19, 2022*, Agenda Item 5 (Project 2021-04 Modifications to PRC-002-2), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_January_Meeting_Minutes_Approved_February_16_2022.pdf.

[5] NERC, *Minutes – Standards Committee Meeting July 19, 2023*, Agenda Item 11 (Project 2021-04 Modifications to PRC-002-2), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/July%20Meeting%20Minutes%20-%20Approved%20August%2023,%202023.pdf.

[6] NERC, *Consideration of Comments – 2021-04 Modifications to PRC-002 – Phase II | Draft 1*, Exhibit G at Item 28.

provides for each Reliability Standard: 1) the percentage of affirmative votes,[7] 2) the quorum reached, and 3) the results of the non-binding poll and quorum for the associated VRFs and VSLs.

Standard	Approval	Quorum	Non-binding Poll / Quorum
PRC-002-5	61.44%	87.96%	54.45% / 86.09%
PRC-028-1	43.33%	87.41%	28.07% / 85.44%
Implementation Plan	42.96%	87.23%	N/A

C. Waiver

The Standards Committee approved waivers of Standard Processes Manual minimum posting length requirements for Project 2021-04 on December 13, 2023, authorizing additional formal comment and ballot periods to be reduced from 45 days to as few as 15 calendar days, with ballot conducted during the last 10 days of the comment period.[8] Additionally, the final ballot was authorized to be reduced to as few as 5 calendar days. NERC Staff sought these waivers to assist the drafting teams in meeting the firm timeline expectations set by FERC Order 901.

D. Second Posting - Comment Period, Additional Ballot, and Non-binding Poll

The proposed Reliability Standards, the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for a 25-day formal comment period from March 18 – April 11, 2024, with a parallel additional ballot and non-binding poll held during the last 10 days of the comment period from April 2 – 11, 2024. There were 73 sets of responses, including comments from approximately 173 different individuals and approximately 115 companies, representing all 10 industry segments.[9] The following table provides for each Reliability Standard:

[7] A ballot needs 66 and two-thirds percentage approval to pass.

[8] NERC, *Minutes – Standards Committee Meeting Dec. 13, 2023*, Agenda Item 10 (Project 2021-04 Modifications to Disturbance Monitoring and Reporting Requirements Waiver), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20December%20Minutes%20-%20Approved%20January%2017,%202024.pdf.

[9] NERC, *Consideration of Comments - 2021-04 Modifications to PRC-002 – Phase II | Draft 2*, Exhibit G at Item 53.

1) the percentage of affirmative votes, 2) the quorum reached, and 3) the results of the non-binding poll and quorum for the associated VRFs and VSLs.

Standard	Approval	Quorum	Non-binding Poll/Quorum
PRC-002-5	79.46%	89.42%	77.96% / 84.96%
PRC-028-1	50.03%	89.26%	44.83% / 86.59%
Implementation Plan	66.61%	87.96%	N/A

E. Third Posting - Comment Period, Initial Ballot, and Non-binding Poll

The proposed Reliability Standards, the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for a 17-day formal comment period from May 31 – June 17, 2024 (extended from 15 days to reach quorum), with a parallel additional ballot and non-binding poll held during the last 12 days of the comment period from June 5 – 17, 2024. There were 61 sets of responses, including comments from approximately 144 different individuals and approximately 92 companies, representing all 10 industry segments.[10] The following table provides for each Reliability Standard: 1) the percentage of affirmative votes, 2) the quorum reached, and 3) the results of the non-binding poll and quorum for the associated VRFs and VSLs.

Standard	Approval	Quorum	Non-binding Poll/Quorum
PRC-002-5	77.13%	79.93%	79.88% / 75.56%
PRC-028-1	46.77%	79.26%	48.15% / 76.63%
Implementation Plan	62.60%	77.74%	N/A

F. Fourth Posting - Comment Period, Additional Ballot, and Non-binding Poll

Proposed Reliability Standard PRC-028-1,[11] the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for a 21-day formal comment period from July 22 – August 12, 2024, with a parallel additional ballot held during the last 10 days of the comment period from August 2 – August 12, 2024. There were 60 sets of responses, including comments

[10] NERC, *Consideration of Comments - 2021-04 Modifications to PRC-002 – Phase II | Draft 3,* Exhibit G at Item 80.

[11] PRC-002-5 passed the previous additional ballot (conducted June 5-17, 2024).

from approximately 135 different individuals and approximately 91 companies, representing all 10 industry segments.[12] The following table provides for each Reliability Standard: 1) the percentage of affirmative votes, 2) the quorum reached, and 3) the results of the non-binding poll and quorum for the associated VRFs and VSLs.

Standard	Approval	Quorum	Non-binding Poll/Quorum
PRC-028-1	80.70%	87.04%	77.51% / 86.59%
Implementation Plan	84.55%	85.04%	N/A

G. Final Ballot

The proposed Reliability Standards and associated definitions, the associated Implementation Plan, VRFs, VSLs, and other associated documents were posted for a 7-day final ballot from September 12 – 18, 2024. The following table provides for each Reliability Standard: 1) the percentage of affirmative votes, and 2) the quorum reached.

Standard	Approval	Quorum
PRC-002-5	84.20%	83.21%
PRC-028-1	83.85%	88.52%
Implementation Plan	84.63%	86.86%

H. Board of Trustees Adoption

The NERC Board of Trustees adopted the Reliability Standards and the associated elements on October 8, 2024.[13]

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[12] NERC, *Consideration of Comments - 2021-04 Modifications to PRC-002 – Phase II | PRC-028-1*, Exhibit G at Item 102.

[13] NERC, *Board of Trustees Agenda Package*, Agenda Item 2a (Project 2016-02 Modifications to CIP Standards) (Oct. 8, 2024), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board%20of%20Trustees%20Open%20Meeting%20Agenda%20Package%20October%208%202024%20Attendees.pdf.

Project 2021-04 Modifications to PRC-002 - Phase II

Related Files

Status

Final ballots concluded at **8 p.m. Eastern, Wednesday, September 18, 2024** for the following standards and implementation plan:

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

The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* **Docket No. RM22-12-000** *on October 19, 2023.*

To assist industry in this comment and ballot period, NERC has released a **Milestone 2 Summary** that provides high-level overview of the current state of the associated projects and their interrelationships. The drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Background
This project will be completed in two phases. The first phase addressed the scope regarding notifications relative to the sequence of events recording (SER) and fault recording (FR) data, and to clearly identify the BES Element owners that need to have SER and FR data for transformers and transmission lines with the associated identified bus in the Glencoe Light and Power SAR.

The second phase will address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements. A new Standard PRC-028-1 - Disturbance Monitoring and Reporting Requirements for Inverter Based Resources has been developed to cover the IRPTF SAR work scope.

Standard(s) Affected – PRC-002-4 Disturbance Monitoring and Reporting Requirements

Purpose/Industry Need
The purpose of PRC-002 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where SER and FR data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES).

With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices and periodic assessments, the location requirements and associated periodic assessments need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.

Subscribe to this project's observer mailing list
Select "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-04 Modifications to PRC-002" in the Description Box.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **PRC-002-5** Clean **(109)** | Redline to Last Posted **(110)** | Redline to Last Approved **(111)** **PRC-028-1** Clean **(112)** | Redline to Last Posted **(113)** **Implementation Plan** Clean **(114)** | Redline to Last Posted **(115)** **Supporting Materials** **VRF/VSL Justification** PRC-002-5 **(116)** PRC-028-1 **(117)** **Technical Rationale** **PRC-002-5** Clean **(118)** | Redline to Last Posted **(119)** **PRC-028-1** Clean **(120)** | Redline to Last Posted **(121)**	**Final Ballot** Info **(122)** Vote	09/12/24 – 09/18/24	**Ballot Results** PRC-002-5 **(123)** PRC-028-1 **(124)** Implementation Plan **(125)**	

Draft 4 **The drafting team decided to remove "4.1.1. Transmission Owner that owns equipment as identified in section 4.2" from the Applicability and all of the Transmission Owner referenced in the Requirements of Standard PRC-028-1** **PRC-028-1 *Updated** Clean **(89)** | Redline to Last Posted **(90)** **Implementation Plan *Updated** Clean **(91)** | Redline to Last Posted **(92)** **Supporting Materials** Unofficial Comment Form (Word) **(93)** **PRC-028-1 VRF/VSL Justifications*Updated** Clean **(94)** | Redline to Last Posted **(95)** **PRC-028-1 Technical Rationale *Updated** Clean **(96)** | Redline to Last Posted **(97)** Consideration of FERC Order 901 Directives **(98)**	Additional Ballots and Non-binding Polls Ballot Open Reminder **(103)** Updated Info **(104)** Info **(105)** Vote	08/02/24 – 08/12/24	Ballot Results PRC-028-1 **(106)** Implementation Plan **(107)** Non-binding Poll Result PRC-028-1 **(108)**	
	Comment Period Updated Info **(99)** Info **(100)** Submit Comments	07/22/24 – 08/12/24	Comments Received **(101)**	Consideration of Comments **(102)**
Draft 3 **PRC-002-5** Clean **(61)** | Redline to Last Posted **(62)** | Redline to Last Approved **(63)** **PRC-028-1** Clean **(64)** | Redline to Last Posted **(65)** **Implementation Plan** Clean **(66)** | Redline to Last Posted **(67)** **Supporting Materials** Unofficial Comment Form (Word) **(68)** **VRF/VSL Justification** PRC-002-5 Clean **(69)** | Redline to Last Posted **(70)** PRC-028-1 Clean **(71)** | Redline to Last Posted **(72)** **Technical Rationale** PRC-002-5 Clean **(73)** | Redline to Last Posted **(74)** PRC-028-1 2 Clean **(75)** | Redline to Last Posted **(76)**	Additional Ballots and Non-binding Polls Updated Info **(81)** (Ballot Reminder) Updated Info **(82)** (Extension) Info **(83)** Vote	06/05/24 – 06/17/24 (extended to reach quorum)	Ballot Results PRC-002-5 **(84)** PRC-028-1 **(85)** Implementation Plan **(86)** Non-binding Poll Results PRC-002-5 **(87)** PRC-028-1 **(88)**	
	Comment Period Updated Info (Extension) **(77)** Info **(78)** Submit Comments	05/31/24 – 06/17/24 (extended)	Comments Received **(79)**	Consideration of Comments **(80)**
Draft 2 **PRC-002-5** Clean **(37)** | Redline to Last Posted **(38)** | Redline to Last Approved **(39)** **PRC-028-1** Clean **(40)** | Redline to Last Posted **(41)** **Implementation Plan** Clean **(42)** | Redline to Last Posted **(43)** **Supporting Materials** Unofficial Comment Form (Word) **(44)** **VRF/VSL Justification** PRC-002-5 **(45)** (no change from last posting) PRC-028-1 Clean **(46)** | Redline to Last Posted **(47)** **Technical Rationale** PRC-002-5 **(48)** (no change from last posting) PRC-028-1 Clean**(49)** | Redline to Last Posted **(50)**	Additional Ballots and Non-binding Polls Updated Info**(54)** (Ballot Reminder) Info **(55)** Vote	04/02/24 – 04/11/24	Ballot Results PRC-002-5 **(56)** PRC-028-1 **(57)** Implementation Plan **(58)** Non-binding Poll Results PRC-002-5 **(59)** PRC-028-1 **(60)**	
	Comment Period Info **(51)** Submit Comments	03/18/24 – 04/11/24	Comments Received **(52)**	Consideration of Comments **(53)**
Waiver**(36)**	Standards Committee accepted the waiver on December 13, 2023.			

Draft 1 **PRC-002-5** Clean **(17)** | Redline **(18)** **PRC-028-1** **(19)** Implementation Plan **(20)** **Supporting Materials** Unofficial Comment Form (Word) **(21)** **VRF/VSL Justification** PRC-002-5 **(22)** PRC-028-1 **(23)** **Technical Rationale** PRC-002-5 **(24)** PRC-028-1 **(25)**	Initial Ballots and Non-binding Polls Updated Info (Ballot Reminder) **(29)** Info **(30)** Vote	09/05/23 - 09/14/23	Ballot Results PRC-002-5 **(31)** PRC-028-1 **(32)** Implementation Plan **(33)** Non-binding Poll Results PRC-002-5 **(34)** PRC-028-1 **(35)**	
	Join Ballot Pools	08/01/23 - 08/30/23		
	Comment Period Info **(26)** Submit Comments	08/01/23 - 09/14/23	Comments Received **(27)**	Consideration of Comments **(28)**

Draft Postings from Phase I of this Project are Omitted from this Filing

SAR Glencoe Light Clean **(13)** | Redline (14) **SAR IRPTF** *updated Clean**(15)** | Redline**(16)**	The Standards Committee accepted these SARs on January 19, 2022.			
Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(11)**	Nomination Period Info (Updated) **(12)** Submit Nominations	06/14/21 – 07/30/21 (Extended)		
SAR Glencoe Light (Formal) **(1)** **SAR IRPTF** (Informal) **(2)** **Supporting Materials** Unofficial Comment Form - Glencoe Light (Word) **(3)** Unofficial Comment Form - IRPTF (Word) **(4)** IRPTF Review of NERC Reliability Standards White Paper **(5)**	Comment Period Info (Updated) **(6)** Submit Comments	06/14/21 – 07/13/21	Comments Received Glencoe Light **(7)** Comments Received IRPTF **(8)**	Consideration of Comments Glencoe Light **(9)** Consideration of Comments IRPTF **(10)**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	April 8, 2021		
SAR Requester			
Name:	Terry Volkmann		
Organization:	Glencoe Light and Power NCR11444		
Telephone:	612-419-0672	Email:	terrylvolkmann@gmail.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The purpose of PRC-002-2[1] is to have adequate sequence of events recording (SER) and fault recording (FR) data available to facilitate analysis of Bulk Electric System[2] (BES) disturbances.			

[1] NERC Reliability Standard PRC-002-2 Disturbance Monitoring and Reporting Requirements (https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&Jurisdiction=United%20States)

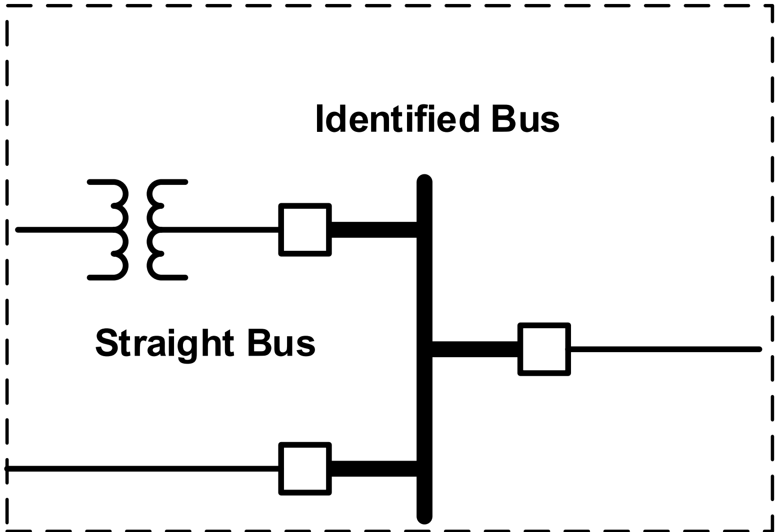
[2] See Glossary of Terms Used in NERC Reliability Standards (https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf)

Requested information
Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data and implicitly obligates these transformer or transmission line BES Element owners to either: 1. work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on for compliance, or 2. the transformer or transmission line BES Element owner must install its own equipment that is duplicative to the identified BES Bus recording equipment. Below is Requirement R1 for reference: **R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **1.1.** Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1. **1.2.** Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements **require** SER data and/or FR data. **1.3.** Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan. Notifications for FR data are being sent to BES Element owners that extend well beyond the BES bus boundary described in PRC-002-2 Attachment 1 as "a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid." Notifying BES Element owners beyond this boundary unnecessarily obligates the BES Element (i.e., transformer or transmission line) owner to Requirement R3, including joint owners.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal of the proposed project is to clarify the necessary notifications in Requirement R1, Part 1.2 relative to FR data, and clearly identify the BES Element owners that need to have FR data for transformers and transmission lines with the associated identified bus.
Project Scope (Define the parameters of the proposed project):
The scope should include modifying Requirement R1, Part 1.2 to clarify notifications, which may include but is not limited to separating the SER data and/or FR data regarding notification. Additionally, Requirement R3 should be modified so that it is abundantly clear to the applicable Transmission Owner

Requested information
and Generator Owner when their BES Element must have FR data for an applicable transformer or transmission line.
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[3] 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 Transmission Owner (TO) applying the method in Attachment 1 who identifies a BES bus is in the ideal position to know which BES Elements (i.e., circuit breakers, transformer and transmission line) are connected to a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. Additionally, the identified BES bus owner should know who owns the particular BES Element (i.e., circuit breaker) that need FR data to capture disturbances on generators, transformers and transmission lines as identified in Requirement R3. Owners of BES Elements beyond the physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid should not be notified, unless their FR data is needed to complete the identified BES bus FR data. Requirement R1, Part 1.1 uses a method and BES bus definition[4] outlined in Attachment 1 to identify BES buses that require SER data and/or FR data. Part 1.2 requires the notification of other BES Element owners connected to the identified BES bus under Requirement R1, Part 1.1. As currently written, a notification is required regardless of whether the identified BES bus owner has FR data for the intended BES Element (i.e., transformer or transmission line) or owns the BES Elements directly connected to the identified BES bus. Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. This will eliminate unnecessary notifications and obligations transformer and transmission line owners to compel other entities to have FR data when there is no authority to do so. In these cases, the other BES Element owner(s) have to rely on FR data from another entity that does not have the obligation under the standard Additionally, clarifying the BES Element for which FR data is required will reduce auditing needs resulting from notifying BES Element owner who should not be responsible to have FR data as well as reducing the cost burden of meeting the reliability need for FR data.

[3] 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.

[4] Attachment 1, Step 1: Determine a complete list of BES buses that it owns. For the purposes of this standard, a single **BES bus** includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Requested information
   The above figure of a straight bus is the simplest BES bus configuration contained within a common ground grid. Only the BES circuit breakers are connected to the identified BES bus. In this case it is clear concerning SER data in Requirement R2 because the circuit breaker is "directly connected." However, to achieve the need for FR data in Requirement R3, the identified BES bus owner notifies the transformer and transmission line owners under Requirement R, Part 1.2 thus obligating them to have FR data where the circuit breaker is directly connected and the logical BES Element to record FR data. Under the current Requirement R3, the notified GO or TO transformer or line owner will need to contact the circuit breaker owner in hope of obtaining FR Data or install their own equipment. The GO or TO cannot compel the circuit breaker owner to have FR data. Additionally, relying on another entity that has no reliability responsibility for complying with PRC-002-2 places the transformer or transmission line owner at risk if the other entity fails to have the necessary and adequate FR data. The intent of the standard in Requirement R3 is to have FR data associated with all applicable BES Elements at a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus. Requirement R1, Part 1.2 should only require notification to the BES Element (i.e., circuit breaker) owner directly connected with the identified BES bus. Having the appropriate BES Elements identified at the same voltage level within the same physical location sharing a common ground grid that require SER and/or FR data will help facilitate obtaining data by only having to seek the data from those entities directly connected to the identified BES bus. However, the current standard could be interpreted that generation, transformer and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus. As such, any modifications should consider alternative approaches that will achieve the intent of the standard while reducing associated cost and compliance burdens.

Requested information
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
None, the proposed modification above eliminates the unnecessary cost of being required to have FR data due to expanded notifications and the administrative burden to transformer and transmission line owners when these entities generally do not own the BES Elements that actually record the FR data.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owner and Generation Owner
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
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)?
A SAR was submitted by the NERC Inverter-based Resource Performance Task Force (IRPTF) to address potential gaps and improvements based on the work and findings of the IRPTF was authorized for posting by the NERC Standards Committee on January 20, 2021.
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.
Standard Implementation Guide or Practice Guide could provide the necessary clarity; however, these documents cannot change the strict language of the PRC-002-2 Reliability Standard. Nothing is being considered at the present time.

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.

[5] 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	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

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

For Use by NERC Only

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

	☐ SAR denied or proposed as Guidance document

Version History

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

Standard Authorization Request (SAR)

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

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

<table>
<tr><th colspan="4">Requested information</th></tr>
<tr><td>SAR Title:</td><td colspan="3">PRC-002-2 Disturbance Monitoring and Reporting Requirements</td></tr>
<tr><td>Date Submitted:</td><td colspan="3">June 10, 2020</td></tr>
<tr><td colspan="4">SAR Requester</td></tr>
<tr><td>Name:</td><td colspan="3">Allen Shriver, Chair
Jeffery Billo, Vice Chair</td></tr>
<tr><td>Organization:</td><td colspan="3">Inverter-Based Resource Performance Task Force (IRPTF)</td></tr>
<tr><td>Telephone:</td><td>Allen: 561-904-3234
Jeffery: 512-248-6334</td><td>Email:</td><td>Allen.Schriver@NextEraEnergy.com
Jeff.Billo@ercot.com</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">The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The “IRPTF Review of NERC Reliability Standards White Paper” was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed.

The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR) data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES).</td></tr>
</table>

Requested information
Requirements R1 and R5 are written with a focus on synchronous machine dominated systems with periodic review of monitoring equipment needs for the system. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. Inverter-based resources (IBRs) do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices. Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events. With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices and periodic assessments, the location requirements and associated periodic assessments need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise PRC-002-2 to address gaps within the existing standard. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS buses for which SER and FR data is required provides adequate monitoring of BES Disturbances. This may include updates to supplemental information such as the previously provided “Median Method Excel Workbook”. b. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS Elements for which DDR data is required provides adequate monitoring of BES disturbances. c. Consider other manners in which to add to, modify or clarify the existing requirements to ensure adequate monitoring of BES disturbances.

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data. However, BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring, though it is possible that monitoring in these areas is needed for disturbance analysis, as was the case in the Blue Cut Fire and Canyon 2 Fire events. Requirement R5, identifies BES locations based on a size criteria for generating resources and other critical elements such as HVDC, IROLs and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. In regard to generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. However, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR devices to ensure adequate coverage for disturbance analysis while balancing cost impacts.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The SAR proposes to modify PRC-002-2 requirements. The cost impact is unknown, however, the cost of disturbance monitoring hardware is approximately $50,000 to $100,000 per installation if the existing onsite equipment is not already set up for monitoring and storage.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):

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

Requested information
IBRs contribute very little short circuit MVA and are typically smaller in aggregate nameplate rating when compared to legacy synchronous resources. The criteria for selecting disturbance monitoring locations should take this into account.
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, Reliability Coordinator, Generator Owner, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This issue was captured in the "IRPTF Review of NERC Reliability Standards White Paper" which was approved by the Operating Committee and the Planning Committee. Additionally, the IRPTF produced "BPS-Connected Inverter-Based Resource Performance"(see Chapter 6) and "Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources" reliability guidelines touch on monitoring considerations for IBRs.
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)?
N/A
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The IRPTF did not identify any alternatives since there is a gap in PRC-002-2.

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

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

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

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

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

For Use by NERC Only

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

Version History

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1	June 3, 2013		Revised
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Unofficial Comment Form

Project 2021-04 Modifications to PRC-002-2

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System (SBS)] to submit comments on **Project 2021-04 Modifications to PRC-002-2 Standard Authorization Request (SAR).** Comments must be submitted by **8 p.m. Eastern, Tuesday, July 13, 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 R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data and implicitly obligates these transformer or transmission line BES Element owners to either:

1. work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on for compliance, or
2. the transformer or transmission line BES Element owner must install its own equipment that is duplicative to the identified BES Bus recording equipment.

The goal of the proposed project is to clarify the necessary notifications in Requirement R1, Part 1.2 relative to FR data, and clearly identify the BES Element owners that need to have FR data for transformers and transmission lines with the associated identified bus.

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:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2021-04 Modifications to PRC-002-2

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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.

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The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR) data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES).

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:

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

IRPTF Review of NERC Reliability Standards

NERC Inverter-Based Resource Performance Task Force (IRPTF)
White Paper - March 2020

Executive Summary

The electric industry is still experiencing unprecedented growth in the use of inverters as part of the bulk power system and growth is possibly creating new circumstances where current standards may not be sufficiently addressing those needs. As a result, the NERC Planning Committee (PC) and Operating Committee (OC) assigned the task of evaluating today's current standards and requirements to the Inverter-Based Performance Task Force (IRPTF). This white paper details the findings of the IRPTF as a result of this activity and makes recommendations on actions that should be taken to address the issues identified.

Recommendations

The IRPTF identified potential gaps and areas for improvements in the following standards, and makes the following recommendations:

1. **FAC-001-3 and FAC-002-2** should be revised to: (a) clarify which entity is responsible for determining which facility changes are materially modifying, and therefore require study, (b) clarify that a Generator Owner should notify the affected entities before making a change that is considered materially modifying, and (c) revise the term "materially modifying" so as to not cause confusion between the FAC standards and the FERC interconnection process;
2. **MOD-026-1** and **MOD-027-1** should either be revised or a new model verification standard should be developed for inverter-based resources (IBRs) since these standards stipulate verification methods and practices which do not provide model verification for the majority of the parameters within an inverter-based resource. For example, the test currently used to comply with MOD-026-1 does not verify the model parameters associated with voltage control behavior during large disturbance conditions;
3. **PRC-002-2** should be revised to require disturbance monitoring equipment in areas not currently contemplated by the existing requirements, specifically in areas with potential inverter-based resource behavior monitoring benefits;
4. Clarifications should be made to **TPL-001-4** to address terminology throughout the standard that is unclear with regards to inverter-based resources the next time the standard is revised. This terminology was not changed in the recently FERC-approved **TPL-001-5** version of the standard; and
5. **VAR-002-4.1** should be revised to clarify that the reporting of a status change of a voltage controlling device per Requirement R3 is not applicable for an individual generating unit of a dispersed power producing resource, similar to the exemption for Requirement R4.

The IRPTF did not identify issues with the existing standard language in the BAL, CIP, COM, EOP, INT, IRO, NUC, PER, or TOP NERC Reliability Standards.

The IRPTF recommends that a Standards Authorization Request (SAR)s be developed to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, due to the continued growth of BPS-connected inverter-based resources.

Background

The IRPTF was formed in 2017 following several grid disturbances involving IBRs. In 2018, the PC and OC approved an IRPTF-developed white paper[1] on identified gaps in PRC-024-2 based on IRPTF's findings following investigations of the grid disturbances. Subsequently, a SAR to modify PRC-024-2 based on the white paper was endorsed by the PC and OC and approved by the NERC Standards Committee. This led to the formation of a Standards Drafting Team (SDT) to modify PRC-024-2.

In 2019, the IRPTF undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there are any further potential gaps or improvements beyond what was identified for PRC-024-2, based on the work and findings of the IRPTF. To accomplish this activity, IRPTF volunteers reviewed all of the current and future enforceable reliability standards, identified potential gaps or improvements, and presented findings to the entire IRPTF. The IRPTF reviewed these findings and finalized a set of recommendations.

The IRPTF acknowledges that the findings in this whitepaper are limited by the knowledge of its members and other issues may be discovered as industry and technology continues to evolve and grow. Any such issues may be addressed through the NERC technical committee or Standards Committee processes. In particular, the IRPTF acknowledges that it did not have subject matter experts in regards to the CIP, COM, NUC, and PER standards. Nevertheless, the IRPTF performed a cursory review of these standards and did not identify any potential gaps or improvements related to IBRs.

A similar review was also conducted as part of NERC Project 2014-01 for dispersed power producing resources.[2] However, industry knowledge of IBR technology and experience with NERC Reliability Standards implementation has evolved since that project was completed. For example, the Project 2014-01 efforts led to revisions of PRC-024-1, but those efforts did not capture the issues IRPTF identified in the PRC-024-2 Gaps Whitepaper.

FAC Standards Issues

The IRPTF identified issues with FAC-001-3 and FAC-002-2 that should be addressed. The IRPTF did not identify any issues with any other FAC standards.

FAC-001-3 and FAC-002-2

[1] PRC-024-2 Gaps White Paper, https://www.nerc.com/pa/Stand/Project%20201804%20Modifications%20to%20PRC0242/NERC%20IRPTF%20PRC-024-2%20Gaps%20Whitepaper.pdf

[2] Project 2014-01 Whitepaper, https://www.nerc.com/pa/Stand/Prjct201401StdrdsAppDispGenRes/DGR_White_Paper_v17_clean_01_13_2016_Final_rev1.pdf

The purpose of FAC-001-3 is to ensure that Facility interconnection requirements exist for Transmission Owners and Generator Owners (GO)s when connecting new or materially modified facilities. The purpose of FAC-002-2 is to ensure studies are performed to analyze the impact of interconnecting new or materially modified facilities on the Bulk Electric System (BES). An ambiguity exists in these standards for both synchronous resources and IBRs, but it may be amplified for IBRs that are comprised of many smaller individual units connected through a network of collection feeder circuits.

Both standards imply that the term "materially modified" should be used to distinguish between facility changes that are required to be studied and those that need not be studied. However, there is not a requirement for any entity to determine what changes are to be considered materially modifying and GOs are not required to notify potentially affected entities of the changes. This has led to confusion and potential reliability issues within industry. For example, a Transmission Planner (TP) may consider an IBR control system software change to be materially modifying, but if the GO does not consider such a change to be materially modifying they will not notify the TP of the change.

Additionally, the frequency of change of components could be higher for IBRs and the magnitude of such changes could vary. For example, due to a rapid change in wind turbine generator (WTG) technology, it is a common practice to re-power an existing wind power plant with bigger blades while keeping the same electrical generator and converter systems (for both Type 3 and Type 4 WTGs). This may be considered a material modification since a new set of bigger blades (e.g., 93 m to 208 m) can produce more power at a lower wind speed. However, the nameplate rating of the plant will remain unchanged. From an interconnection requirements' perspective, it is the electrical generator and converter system that impacts the majority of the steady-state, short-circuit, and dynamic characteristics and therefore will be mostly unchanged. Therefore, the question remains if these sort of repowering projects should be studied under FAC-002-2 R1 and which entity should make that determination. Therefore, the IRPTF recommends these standards be modified to specify which entity is responsible for determining what facility changes should be considered materially modifying and requiring that Generator Owners notify the appropriate affected entities before they make such a change.

The IRPTF further notes that if the plant owner makes a change in electrical generator, power electronic converter, or any control systems (including change of OEMs for partial individual units), it should be considered as "materially modifying". On the other hand, due to the advanced nature of control systems in the power electronic converters, it is not uncommon to have firmware updates (similar to the updates on a personal computer) occasionally that may have no impact on the functionalities of the WTGs or plant-level controls in any way. Therefore, such firmware updates that do not affect the electrical performance of the plant should not be considered as "materially modifying".

Additionally, in FERC-jurisdictional areas, the term "Materially Modification" refers to a new generation project's impact on other generators in the interconnection queue. This has led to widespread confusion across the industry regarding the correct application of these terms related to the FERC Open Access Transmission Tariff (OATT) implementation and the NERC Reliability Standards requirements. The application of these terms is different between the FERC process and the NERC Reliability Standards (specifically FAC-001-3 and FAC-002-2). For example, if a GO changes out the inverters on an existing solar

PV resource, the change may have no impact on other generators in the interconnection queue, and thus would not be considered a material modification under the FERC OATT rules. But such a change could have reliability impacts on the system that should be studied in accordance with FAC-002-2. Any revision to these standards should consider changing the term to avoid this confusion. FAC-001-3 and FAC-002-2 should be modified to clarify the use of “materially modifying”, particularly as it relates to compliance with the standards.

MOD Standards Issues

The IRPTF identified issues with MOD-026-1 and MOD-027-1 that should be addressed. The IRPTF did not identify any issues with any other MOD standards that are not already being addressed in other forums.

MOD-026-1 and MOD-027-1

MOD-026-1 and MOD-027-1 require, among other things, GOs to provide verified dynamic models to their TP for the purposes of power system planning studies. Both standards contain language that is specific to synchronous generators and is not applicable to IBRs. For example, sub-requirement 2.1.3 in MOD-026-1 states that each verification shall include “model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia” The standards should be revised to clarify the applicable requirements for synchronous generators and IBRs. For example, total rotational inertia should not be required for IBRs, while voltage ride-through control settings should only be required of IBRs and not synchronous generators.

To some degree, all dynamic model parameters affect the response of a represented resource in dynamic simulations performed by power engineers. Accurate model response is required for the engineers to adequately study system conditions. Hence, it is crucial that all parameters in a model be verified in some way. However, a significant number of parameters in the models are not verified in the typical verification tests used to comply with MOD-026-1 and MOD-027-1. For example, the test currently used to comply with MOD-026-1 does not verify the model parameters associated with voltage control behavior during large disturbance conditions.

This issue is one of the predominant reasons why ride-through operation modes such as momentary cessation were able to persist and promulgate in IBRs without the knowledge of planners and system operators until the Blue Cut Fire and Canyon 2 Fire events exposed them. The dynamic models did not accurately represent this large disturbance behavior due to the model deficiency and because certain key parameters that govern large disturbance response were incorrectly parameterized. However, many of the same plants that entered momentary cessation mode during these events were able to provide verification reports that demonstrated that the small disturbance behavior driven mainly by plant-level control settings reasonably matched modeled performance in compliance with these standards.

This reliability gap exists for both synchronous generators and IBRs. However, it is potentially more severe for IBRs since their behavior is based more on programmable control functions than for synchronous generators which have behavior that is based more on the physical characteristics of the machine. Both MOD-026-1 and MOD-027-1 should be reviewed and potentially revised to provide sufficient clarification for verification of generating resource model parameters, or a new standard should be developed to meet the reliability objective. Additionally, the IRPTF notes that it is not feasible to stage large disturbances for verification purposes, so other methods for verification of model performance under large disturbance conditions may need to be developed.

PRC Standards Issues

The IRPTF identified issues with PRC-002-2 that should be addressed. The IRPTF did not identify any issues with any other PRC standards that are not already being addressed in other forums.

PRC-002-2

The purpose of the NERC standard PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 provide guidance on selecting BES elements where data monitoring is required, which is summarized briefly below.

1. Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data.
2. Requirement R5, identifies BES locations based on a size criteria for generating resources and other critical elements such as HVDC, IROLs and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. In regard to generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

Requirements R1 and R5 are written with a focus on synchronous machine dominated systems. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices, respectively.

Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events.

With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices, the location requirements need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.

TPL Standards Issues

The IRPTF did not identify any requirements that may need to be changed in TPL-007-3, Transmission System Performance for Geomagnetic Disturbance Events, or the upcoming revisions to the standard. The IRPTF did identify several clarifications that may be helpful in the requirements of TPL-001-4, Transmission System Planning Performance Requirements. However, these clarifications are minor in nature and do not warrant changing the standard at this time. These clarifications should be considered by a subsequent SDT if the standard is revised in the future.

TPL-001-4

TPL-001-4 requires Planning Coordinators (PCs) and TPs to assess the reliability of their portion of the BES for various conditions across several specified future years and to plan Corrective Action Plans to address identified performance deficiencies. The requirements and sub-requirements include, among other things, certain simulation assumptions to be used by the planner and performance requirements.

Sub-requirements 3.3 and 4.3 describe simulation assumptions that the planner should use when performing contingency analysis for the steady-state and stability portion of the assessment, respectively. Sub-requirements 3.3.1.1 and 4.3.1.2 each require the planner to include the impact of the "tripping of generators where simulations show generator bus voltages or high side of the [GSU] voltages are less than known or assumed generator" low voltage ride-through capability.

The term GSU transformer can be confusing to GOs of IBR facilities because they will often refer to the transformer that steps the voltage up from the individual inverter (e.g., 600 V) to the collector system voltage (e.g., 34.5 kV). In this case, there is usually another transformer (i.e., the MPT) to step the voltage up from the collector system voltage to transmission system voltage. It was likely the intent of the TPL-001-2 SDT to be referring to transmission system voltages when drafting the language that refers to known or assumed generator low voltage ride-through capability at the high-side of the GSU. Therefore, the language in these sub-requirements should be modified to provide clarity for inverter-based resources.

Sub-requirements 4.1.1 and 4.1.2 provide stability performance criteria when a generator "pulls out of synchronism" in system simulations. Although an inverter-based resource does synchronize with the grid, the phrase "pulls out of synchronism" is typically applicable only to synchronous generators, referring to when a synchronous machine has an angular separation from the rest of the grid. Therefore, these sub-requirements could be clarified by clearly stating that this performance criteria is for synchronous generators.

Sub-requirement 4.3.2 specifies that stability studies must "simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area." It then contains a list of example devices that have dynamic behavior. Not included in this list are power plant controllers and inverter controls, which often dominate the dynamic response of IBRs. While the sub-requirement does not preclude the simulation of plant-level controllers and inverter controls, it would add clarity if they were added to the list.

The suggested clarifications for sub-requirements 3.3, 4.3, 4.1.1, 4.1.2, and 4.3.2 should be considered by a future SDT when editing the standard. However, the IRPTF does not believe the clarifications by themselves warrant changing the standard at this time. It should be noted that the identified issues with TPL-001-4 also apply to the draft TPL-001-5 standard that is awaiting FERC approval as of the publication of this whitepaper.

VAR Standards Issues

The IRPTF identified issues with VAR-002-4.1 that should be addressed. The IRPTF did not identify any issues with any other VAR standards.

VAR-002-4.1

The purpose of VAR-002-4.1 is "to ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection." Requirement R3 requires each Generator Operator (GOP) to notify its Transmission Operator (TOP) of a status change on "the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change." Requirement R4 is similar in that it requires each GOP to notify its TOP of "a change in reactive capability due to factors other than a status change described in Requirement R3."

For dispersed power producing resources, it is not clear if a GOP is required to notify the TOP for the status change of voltage control on an individual generating unit. For example, if an IBR consisting of one hundred inverters has one inverter trip out of service, is the GOP required to notify the TOP per Requirement R3? NERC Project 2014-01 revised VAR-002 Requirement R4 to clarify that it is not applicable to individual generating units of dispersed power producing resources. The IRPTF did not identify any reason why Requirement R3 should be treated differently than Requirement R4 in this respect and recommends VAR-002-4.1 be modified to make this same clarification to Requirement R3.

Conclusion and Recommendation

The IRPTF performed a comprehensive review of NERC Reliability Standards to determine if there were potential gaps for improvements based on the work and findings of the IRPTF. The outcome of this analysis includes the following recommendations:

1. **FAC-001-3 and FAC-002-2** should be revised to address the issues described herein;
2. **MOD-026-1** and **MOD-027-1** should either be revised to address the issues described herein or a new model verification standard should be developed for IBRs
3. **PRC-002-2** should be revised to address the issues described herein;
4. Clarifications should be made to **TPL-001-4** to address the issues described herein the next time the standard is revised. This recommendation also applies to the draft **TPL-001-5**; and
5. **VAR-002-4.1** should be revised to address the issues described herein.

The IRPTF recommends that a SAR(s) be developed to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, due to the continued growth of BPS-connected inverter-based resources.

UPDATED
Standards Announcement
Project 2021-04 Modifications to PRC-002-2 Standard Authorization Requests

Comment Periods Open through July 13, 2021

Now Available

A 30-day formal comment period for Glencoe Light SAR and a 30-day informal comment period for the IRPTF SAR for **Project 2021-04 Modifications to PRC-002-2** Standard Authorization Requests (SARs), are open through **8 p.m. Eastern, Tuesday, July 13, 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 2021-04 Modifications to PRC-002-2” in the Description Box.

RELIABILITY CORPORATION

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:	2021-04 Modifications to PRC-002-2 | Glencoe Light SAR
Comment Period Start Date:	6/14/2021
Comment Period End Date:	7/13/2021
Associated Ballots:	

There were 23 sets of responses, including comments from approximately 56 different people from approximately 50 companies representing 7 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
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

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.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	No
Document Name	
Comment	
We believe that the notified interconnecting entity should have the FR/SER coverage on the notified BES Element(s) jointly owned by the interconnecting entities, which connect to the applicable bus owned by the notifying entity. We do not agree that the requirement calls for FR/SER monitoring on the lines, buses, transformers, and breakers on the bus owned by the notified entity, if the interconnecting BES element is only the line connecting to the bus owned by the notifying entity, as stipulated in the SAR proposal.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The existing language of the standard defines only that the individual entities must provide notification and have data available. Under this language the entities are still free to collaborate in providing SER and FR data. The full submission from Glencoe Light and Power Goes on to stipulate: Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. Following this more prescriptive language recommended by Glencoe limits the opportunity for collaboration.	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Black Hills Corporation would also recommend including more clarification on which party (BES bus owner or BES element owner) is responsible for installing FR and/or SER equipment.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
AEP agrees with the proposed scope, direction, and intended purpose and goals of the proposed SAR as drafted by Glencoe Light and Power. We recommend it be pursued, as we believe the effort would provide clarity and that the resulting efficiencies would benefit industry. While both the IRPTF SAR and the Glencoe Power and Light SAR each focus on revising PRC-002, their perceived needs and expressed goals are quite different. Because only one single SAR governs a project at any point in time, and because the unique efforts for the IRPTF SAR will likely be met with much more resistance than the Glencoe SAR, AEP recommends breaking this project into multiple phases, each with its own SAR governance. The Glencoe SAR will likely encounter less resistance from industry than the IRPTF SAR, so we recommend that the Glencoe SAR govern the first phase of the project. Once that phase is complete, the second phase could then begin with the IRPTF SAR governing Phase 2. Pursuing Project 2021-04 this way would be much more efficient, allowing progress to be made more quickly on the purpose and goal on the Glencoe SAR, and without potential delay associated to any resistance to efforts related to the IRPTF SAR.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The notification and data responsibility requirements in PRC-002 R1 and R3 needs clarification. When identifying BES buses for monitoring bus in this standard is defined as a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid. For the sake of this standard, the BES Elements identified for monitoring should be defined in the same way avoiding including BES Elements that are remote to the identified BES bus-like transmission lines and their remote terminals. The original intent of the standard drafting team was to make sure that the SER and FR data was available at the identified buses, so the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers.	

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

No comments

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Duke Energy does not have comments at this time.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

N/A.

Likes 0	
Dislikes 0	

Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS supports the scope of the SAR submitted by Glencoe Light.	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
As noted by SAR written by Glencoe Light, the existing standard needs to be clarified as to whether it applies to directly connected versus remote buses indirectly connected. Pages 3 & 4 of the Glencoe Light SAR describe cases where ownership, notification, and compliance applicability for SER and/or FR data need to be clarified.	
Likes 0	
Dislikes 0	
Response	
William Steiner - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
MRO agrees with the SAR that, in situations where the identified BES bus owner has the capability to measure and record the required FR data, the notification required by R1.2 and the possession of data required by R3 create compliance burdens for the entities subject to those requirements but may not be the best way to ensure that the data will be available for analysis. However, the solutions proposed in the SAR do not appear to ensure that the obligation to have data will be assigned clearly to one equipment owner. The SAR suggests that the owner of a BES Element connected to an identified BES bus should only be made responsible for having FR data in situations where the owner of the identified BES bus lacks the capability to obtain the data. This, however, would constitute a sort of cascading applicability scheme where the failure of one entity (the bus owner) to meet the	

data requirement would kick the obligation back to the connected BES Element owner. This approach seems difficult to enforce and does not fully mitigate the issue of uncooperative neighboring entities. While not fully supportive of the proposed solutions in the SAR, MRO does support revision of the standard to mitigate the dependency of one equipment owner on another to meet the data possession requirement in R3. Other applicability schemes could likely be utilized to make the applicability of each requirement clear to all entities.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Reclamation recommends the owner of the required equipment be the evaluating entity. Criteria to determine what Facilities require SER/FR and DDR equipment should be provided to remove ambiguity. Reclamation recommends the scope of the SAR also include the items described in the response to Question 2.	
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	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	

Comment	
In general Capital Power (on behalf of Decatur Energy Center and other Group 80 MRRE assets) agrees with the proposed scope. Please see additional comments in response 2.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the concern identified in the Glencoe Light SAR that Requirement R1, Subpart 1.2 does not clearly identify under what conditions notified owners of BES Elements connected to BES busses, identified under Part 1.2 of PRC-002-2; are obligated to install sequence of events recording (SER) and fault recording (FR) equipment. Additionally, given the parallel posting of both the IRPTF and Glencoe Light SARs, consideration should be given to addressing these two SAR under a single project but through a multi-phased approach with the Glencoe Light scope SAR being addressed in the first phase.	
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	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
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 Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
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	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA supports the project scope to modify Requirement R1, Part 1.2 to clarify notifications – it's been unclear both what to expect in return when we send out a notification as well as what to do with a notification when we receive one. Because of this, we have done SER and DFR reviews on stations that were identified to us by other entities on top of completing reviews of our PRC-002-2 identified stations. More clarity is needed on what specifically must happen when you receive a notification. The standard also states that the owner must supply the data upon request, but BPA has worked with other utilities to ensure we don't have gaps. There needs to be some leeway on allowing two or more utilities to have a formal, pre-established agreement if they choose to do so. It helps save utilities on cost if they can.	
Likes 0	
Dislikes 0	

Response

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

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

While Texas RE generally supports the scope of the proposed SAR and the overall intent of the proposed project, Texas RE proposes two additional areas for consideration in the upcoming project to improve the proposed PRC-002 Standard's overall effectiveness. First, the SDT should move periodic requirements set forth in the PRC-002 Implementation Plan directly in the Standard Requirement language contained in PRC-002-2 R1.3. Second, the SDT should review the "Median Method Excel Workbook" for potential anomalies. Texas RE provides additional details on each of these items below.

Periodic Requirements in the PRC-002-2 Implementation Plan

Texas RE is concerned there is a periodic requirement in the Implementation Plan for PRC-002-2, rather than in the requirement itself. Consistent with Standard Processes Manual, Section 4.4.3, implementation plans are intended to describe the proposed effective date, identify new or modified definitions, specify any prerequisite actions that need to be accomplished before entities are held responsible for compliance with the requirements, describe whether any conforming changes to other Reliability Standards will occur, and finally the Functional Entities that will be required to comply with the requirements.

In contrast to these core implementation plan elements, the PRC-002-2 implementation plan sets forth an explicit compliance periodicity that is not solely associated with registered entities' transition to compliance with the PRC-002-2 requirements. In particular, PRC-002-2, R1.3 states that TOs shall "re-evaluate buses at least once every five years and notify other owners…***and implement the re-evaluated list of BES buses as per the Implementation Plan.***" The current PRC-002-2 implementation plan in turn provides that "Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated that list." When read together, therefore, the PRC-002-2 Registered Entities must continue to reference the current PRC-002-2 implementation plan in order to understand the requirement to implement the re-evaluated list of BES buses on a three-year cycle.

Texas RE recommends moving the three-year requirement from the PRC-002-2 implementation plan to the requirement language itself, as it is essentially a periodic requirement for TOs and is no longer associated with the prerequisite actions that need to be accomplished before Registered Entities are held responsible for PRC-002-2 R1.3. Such a change will provide additional clarity to registered entities as well as reduce the number of extraneous documents needed to comply with the standard.

Workbook Anomalies

In addition to explicitly incorporating the three-year BES bus re-evaluation language directly into the PRC-002-2 R1.3 requirement language, Texas RE also recommends the drafting team conduct a general re-evaluation of the "Median Method Excel Workbook" (located on the original project page) to ensure accurate evaluations. During the course of its ongoing compliance engagements, Texas RE staff discovered several potential anomalies and possible incorrect calculations throughout the Workbook. For example, Texas RE noticed the use of "SOER" (Sequence of Events Recording) within the Workbook, which had been removed from a Rationale dialog box in a May 2014 redline:

(https://www.nerc.com/pa/Stand/Project%20200711%20Disturbance%20Monitoring%20DL/PRC-002-2_Disturbance_Monitoring_2014May09_redline.pdf).

Texas RE staff also determined the same number of bus placements based on the example data but that number **differed** from the example provided within the Workbook. When using real world data, it was discovered that there may not be enough guidance to determine bus placement in a repeatable fashion as Workbook instructions appeared to not consider repeat values for three phase short circuit (e.g. multiple busses having the same short circuit values).

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI looks forward to reviewing a future Project 2021-04 SAR, which contains elements of both SARs.

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	
Document Name	

Comment

Capital Power (on behalf of Decatur Energy Center and other Group 80 MRRE assets) appreciates any opportunity to reduce the administrative burden related to certain Reliability Standards. However, in this case, the notification of only the impacted entities may result in instances where, due to an administrative error, a potentially in-scope entity is not notified and assumes it is out of scope because no notification was received. To mitigate this risk, Capital Power recommends one of the following solutions:

- Comprehensive, easily accessible list of all in-scope buses as well as what data is required
    - This will allow all entities, including those who may not have received a direct notification, to ensure that the lack of notification was not due to an administrative error
    - Ideally this list should be stored and/or facilitated on/via a centralized system such as NERC's Align system.
- Positive confirmation of out of scope – TOs should notify all entities of their in-scope or out of scope status

- Develop selection criteria specific to generators (inclusive of synchronous and inverter-based resources). Based on these criteria generators would be accountable and have the mechanism to make their own determination re. which assets require SER and FR.

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

Evergy supports and incorporates by reference Edison Electric Institute’s (EEI) response to Question 2.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

In general PRC-002 is loosely written. BPA has submitted questions to WECC for clarification. R4.3 states “Trigger settings for at least the following: 4.3.1 Neutral (residual) over current. 4.3.2 Phase undervoltage or overcurrent”; this can be interpreted that the XFMR can have a phase undervoltage trigger even though R3 states: “3.1 phase- to neutral voltage for each phase of each specified BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1 Transformers that have a low-side operating voltage of 100kV or above. 3.2.2 Transmission Lines.”

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1,5

Answer	
Document Name	

Comment

Reclamation recommends the PRC-002 SAR include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items:

- In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators.
- Requirement R1.3 should be modified to state the timeframe within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO).
- Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.
- Reclamation recommends adding the sharing of protection system data when requested by the entity performing the R1 evaluation.
- Requirement R12 should be modified to add a required time limit within which to notify the Regional Entity(ies) of a failure of the recording capability. Regional Entities need to know as soon as the failure occurs or is discovered, not up to 90 days later.

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.

Likes 0	
Dislikes 0	

Response

William Steiner - Midwest Reliability Organization - 10

Answer	
Document Name	

Comment

- MRO has noted that the standard is complicated and difficult to interpret. Proper interpretation requires a nuanced understanding of various terms including "BES bus", "BES Element", "connected", and "directly connected." These terms are defined by a combination of the NERC Glossary of Terms and the standard itself. The uses of these terms in the standard provide further insight into how the terms should be understood. A more straightforward approach to defining terms in the standard would likely help to clarify the locations where recording is required as well as the delineation of responsibilities for obtaining data.

- The SAR includes the statement "the current standard could be interpreted that generation, transformer and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus" and implies that this is somehow an unnecessary or undesirable interpretation. However, it is MRO's opinion that this is the proper interpretation as R3 does not dictate the exact location of current measurement, only that the entity must have current data for the applicable transmission lines and transformers. If, for some reason, the only location where current sensing and recording equipment was installed was at the remote end of a transmission line or transformer, it would make sense to utilize that equipment rather than require installation of new equipment nearer to the identified BES bus.

- Clarifications regarding the current version of the standard and MRO's interpretation:

  - R1.2 notifications do not obligate entities to have data, only R3 does that. The notifications ensure that BES Element owners with R3 obligations are aware of those obligations. An overreaching notification from the identified BES bus owner to an adjacent owner of equipment that does not meet the criteria given in R3 would not create any compliance obligation for the adjacent owner.
  - R1.2 and R3 are consistent with each other in addressing BES Elements "connected to the BES buses identified in Requirement R1."

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

Proccess qustion, with two different SAR write-ups (IRPTF from June 2020 and Glencoe Light from April 2021) out for comment, would the Standards Committee assign one SDT to both of these SARs or would the SARs be combined into one SAR?

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

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

The proposal by Glencoe light does not address following issues, which should be addressed by the Standards Drafting Team on Requirement R1.

- The Requirement R1.2 obligates the notifying entity to notify the interconnecting entity about the FR or SER monitoring requirement on the interconnecting BES element(s) within 90 days of the determination of the BES buses. But it does not say anything about the obligation of the notified interconnecting entity in terms of time limits on their response or confirmation about implementing the FR/SER monitoring. There is provision to notify interconnecting FR/ER monitoring for the interconnecting BES element(s), but thereafter standard leaves it open. There is no follow-up on actual implementation of the FR/SER monitoring. The requirement should set some time limit on the notified entity to confirm/ or resolve issues if any towards implementing the FR/SER requirement. It should also address issues, when the applicable buses list of the notified interconnecting entity does not include the bus to which the interconnecting BES element in question is connecting.
- In the requirement R5, the Reliability Coordinator (RC) notifies the entities about DDR requirement. The RC should provide more details with the notification. Currently the RC notification merely includes the requirement no in the columns. It does not include why or how the requirement number was applied. For example If a notification of DDR monitoring goes to an entity under R5.1.5 (UVLS) or 5.1.2 (Stability of System Operating limits), then the standard does not clarify RC responsibility to notify other participating entities. The RC notification does not provide the details. What about the FR/SER monitoring requirement on those interconnections between entities if the buses do not figure in the 20% applicable buses list of the concerned entities?). The standard should address this.
- The requirement R1.1 should address step 8 of the algorithm in attachment 1 of the standard. For example, step 8 does not necessarily include the case of growing inverter-based resource monitoring. It has been noticed that while applying step 1-step7, the applicable buses tend to concentrate in the high MVA zones and distributed monitoring across the network does not occur. The standard or the algorithm need to be tweaked to address this issue.

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

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	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.	
Likes 0	
Dislikes 0	
Response	

“Comments received from Jamie Johnson – California ISO”
Question 1
☒ Yes

Comments: Any clarifications to the scope of NERC registered entities responsibilities promote clarity and add to reliability activities.

Question 2 (no additional comments)

“Comments received from Wayne Sipperly – NAGF”
Question 1
☒ **Yes**

Comments:
The NAGF agrees with the proposed scope to clarify the notification and data responsibility requirements in PRC-002 R1 and R3. The BES Elements identified for monitoring should be defined as “a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid” to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Where the intent is to ensure that the SER and FR data is available at the identified buses, the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers

Question 2 (additional comments)
Comments:
PRC-002 R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.

The NAGF notes that the existing PRC-002-2 Rational section regarding R3 states that an FR exception exists for “Generator step-up transformers GSUs) and leads 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”. This needs to be clarified with regard to PRC-002-2 Requirement 1. TOs should be required to send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

“Comments received from Pamela Hunter – Southern Company”
Question 1
☒ **Yes**

Comments:
The notification and data responsibility requirements in PRC-002 R1 and R3 needs clarification.

The BES Elements identified for monitoring should be defined as “a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid” to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Where the intent is to make sure that the SER and FR data is available at the identified buses, the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers.

Question 2 (additional comments)
Comments:
R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.

The usual order of precedence for NERC standards is that the Rationale section only explains the requirements and does not modify them. PRC-002-2 breaks this rule by treating SER and FR in a one-size-fits-both fashion in R1, then saying in the Rationale section that an FR exception exists for, 'Generator step-up transformers (GSUs) and leads 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.' It is awkward to have a letter from the TO saying that FR is required, and having to point-out to auditors that the Rationale section of PRC-002-2 overrules. PRC-002-3 should have TOs send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

"Comments received from Daniel Gacek – Exelon"
Question 1
☒ **Yes**

Comments: Exelon agrees that the BES element owner should be responsible for data required for PRC-002-2. The BES Elements identified for monitoring should be defined as "a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid" to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Question 2 (additional comments)
Comments:
Receiving notifications from a TO that data is not required for a BES Element is beneficial and such notifications should not be eliminated by changes to the standard.

Comment Report

Project Name:	2021-04 Modifications to PRC-002-2 | IRPTF SAR
Comment Period Start Date:	6/14/2021
Comment Period End Date:	7/13/2021
Associated Ballots:	

There were 23 sets of responses, including comments from approximately 50 different people from approximately 44 companies representing 7 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
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

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.

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS does not support the scope of the SAR submitted by the NERC Inverter-based Resource Performance Task Force (IRPTF) because is too broad and does not provide specific information on the changes to be addressed by the standard drafting team. Additionally, AZPS does not agree that the IRPTF White Paper provides sufficient justification for revising the standard. AZPS's experience has shown that any significant inverter based resources tie into large substations for which the MVA requirement would cover the need for monitoring.	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
The City of Tallahassee (TAL) believes that requiring additional monitoring equipment is not cost-effective given the minor contribution to the BES in terms of fault current. TAL is unsure how the data collected will provide a substantial gain to the BES.	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA disagrees with this project scope. PRC-002-2 Attachment 1, Step 8 already says "the additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data." It then provides recommendations for selecting additional bus locations. We do not only rely on PRC-002-2 to require disturbance monitoring and recording. We have our own requirements for when to install	

disturbance monitoring and recording and the TO should know their system well enough to know when and where they need to monitor. In order to completely eliminate the possibility of not having data available for event analysis, you'd have to require monitoring and recording at every substation which may or may not be possible. The SAR mentions the IBRs don't provide enough fault current, thus they can contribute to a fault. PRC-002 is for wide area faults and reconstructing them. This SAR may be better applied to PRC-023 or another protection standard. The owners need to update their own standards for SER/FR equipment or at least protective systems (most offer both limited SER/FR capability).	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
No 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	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	

AEP believes there may be benefit in pursuing this SAR, however we do not believe that the burden to install SER, FR, and DDR should be placed on the Transmission Owner. Rather, any such obligations to do so should be placed solely on the Generator Owner of those resources.

We believe Attachment One should be revised to make it absolutely clear that it governs Transmission assets only. Generation resources deserve their own distinct selection criteria for R1 and R3, one that is inclusive of both synchronous generation and inverter based generation. Generator Owners should be able to make their determination on which assets require FR and SER solely on the resource in question, and not based on analysis regarding how that asset is compared to others. One suggested method to consider would be establishing individual and aggregate thresholds for when SER and FR would need to be installed.

While both the IRPTF SAR and the Glencoe Power and Light SAR each focus on revising PRC-002, their perceived needs and expressed goals are quite different. Because only one single SAR governs a project at any point in time, and because the unique efforts for the IRPTF SAR will likely be met with much more resistance than the Glencoe SAR, AEP recommends breaking this project into multiple phases, each with its own SAR governance. The Glencoe SAR will likely encounter less resistance from industry than the IRPTF SAR, so we recommend that the Glencoe SAR govern the first phase of the project. Once that phase is complete, the second phase could then begin with the IRPTF SAR governing Phase 2. Pursuing Project 2021-04 this way would be much more efficient, allow progress to be made more quickly on the purpose and goal on the Glencoe SAR, and without potential delay associated to any resistance to efforts related to the IRPTF SAR.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

Step 8 in Attachment 1 for R1 already provides a means by which bus locations not captured in the highest 10% bus fault current calculations are selected for SER and FR data monitoring to achieve the 20% total. Locations with Inverter Based Resources can be added to the list of recommended locations.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	

The rationale for R1 on page 22 explains in detail the data analysis efforts which have gone into developing a methodology for identifying optimum number of buses. The study established a strong correlation between the short circuit MVA level available at a bus and its relative size based on voltage level, no. of transmission lines and other BES elements connected have an impact on system reliability. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment. Though entities could cover the inverter-based resources under optional buses in Step 8 of the algorithm in attachment 1 of the standard.

Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	

The existing standard targets BES elements with short circuit MVA in the top 20% which could leave out inverter-based resources. Recent events involving inverter-based resources (IBR), such as the Blue Cut Fire and Canyon 2 Fire, have demonstrated the need to monitor some inverter-based resources. The Project 2021-04 SAR (the portion written by the IRPTF) addresses the need to monitor some IBRs.

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	

Comment	
Reclamation agrees with the addition of a requirement to further enhance SER/FR and DDR equipment in facilities on the premise that the information obtained not only enhances BES reliability but also enhances an entity's ability to troubleshoot and repair Facilities, further reduce operating costs, and increase reliability. Reclamation recommends the scope of the SAR also include the items described in the response to Question 2.	
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	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1.	
Likes 0	
Dislikes 0	
Response	

Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power (CP) (on behalf of Decatur Energy Center LLC and other MRRE group 80 assets) supports the NAGF submitted comments on this item.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
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	

David Jendras - Ameren - Ameren Services - 1,3,6	
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	

Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
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	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI supports the concerns identified in the IRPTF SAR that current processes contained within PRC-002-2 (Attachment 1) used to identify BES buses where sequence of event (SER) and fault recording (FR) equipment are to be installed generally do not require the placement of this equipment on buses where IBR resources are prevalent. The SAR SDT should consider the potential fault recording differences that may be required by IBRs, such as the possible need for faster sampling rates for IBRs, while providing little value for synchronous resources. EEI also suggests SER and FR equipment might be efficiently placed at the point of aggregation where this information would be more useful. Additionally, given the parallel posting of both the IRPTF and Glencoe Light SARs, consideration should be given to addressing these two SAR under a single project but through a multi-phased approach with the Glencoe Light scope SAR being addressed in the first phase.	
Likes 0	
Dislikes 0	
Response	

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

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI looks forward to reviewing a future Project 2021-04 SAR, which contains elements of both SARs.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	

Capital Power (CP) (on behalf of Decatur Energy Center LLC and other MRRE group 80 assets) supports the NAGF submitted comments on this item.

In addition, CP supports Reclamation's recommendation of the following (modified slightly):

PRC-002 SAR should include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items:

- In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators.
- Requirement R1.3 should be modified to state the timeframe / implementation period within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO).
    - This is particularly important when it comes to newly identified BES buses in remote areas where DDR equipment may not already be on-site and will need to be designed, procured, and installed.
- Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.
- The addition of a requirement allowing exemption based on equipment limitation, age of asset etc. If a newly identified BES Bus happens to be connected to an existing asset nearing the end of its useful life, the cost / benefit of the installation of additional DDR equipment should be considered.

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	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
In general, PRC-002 is loosely written. BPA has submitted questions to WECC for clarification. R4.3 states "Trigger settings for at least the following: 4.3.1 Neutral (residual) over current. 4.3.2 Phase undervoltage or overcurrent"; this can be interpreted that the XFMR can have a phase undervoltage trigger even though R3 states: "3.1 phase- to neutral voltage for each phase of each specified BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1 Transformers that have a low-side operating voltage of 100kV or above. 3.2.2 Transmission Lines."	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	
Reclamation recommends the PRC-002 SAR include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items: • In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators. • Requirement R1.3 should be modified to state the timeframe within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO).	

- Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.

- Reclamation recommends adding the sharing of protection system data when requested by the entity performing the R1 evaluation.

- Requirement R12 should be modified to add a required time limit within which to notify the Regional Entity(ies) of a failure of the recording capability. Regional Entities need to know as soon as the failure occurs or is discovered, not up to 90 days later.

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

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

Answer	
Document Name	

Comment

The proposal from IRPTF does not address following issues, which the Standards Drafting Team (SDT) should consider.

- The requirement R1.1 should address step 8 of the algorithm in attachment 1 of the standard. For example, step 8 does not necessarily include the case of growing inverter-based resource monitoring. It has been noticed that while applying step 1-step7, the applicable buses tend to concentrate in the high MVA zones and distributed monitoring across the network does not occur. The standard or the algorithm need to be tweaked to address this issue.
- The algorithm could adopt the weighted points technique considering MVA, Voltage, NO. of lines, IROL (Interconnection Reliability Operating Limit) and SOL (Stability Operating Limit), UVLS schemes, and Vegetation parameters to derive a distributed FR/SER/DDR monitoring.
- Standard should address follow through action by notified entities participating in interconnection with the notifying entity in a time bound way to ensure adequate FR/SER/DDR monitoring in zones, where multiple entities are involved. DDR notification by Reliability Coordinators (RC) should have more details justifying the DDR requirement than merely quoting the requirement nos. in the notification document.

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

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

N/A

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 to add an implementation period for newly identified BES buses. During five year reviews, new BES buses are identified, and particularly in the case of BES buses like ones that may be identified as a result of this SAR that are interconnected at remote areas of the system, DDR equipment may not already be on-site and will need to be designed, procured, and installed.

Likes 0	

Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Duke Energy does not have comments at this time.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	
Document Name	

Comment

PRC-002-2 says in Requirement R1.2 that TOs shall, “Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.” The expression “and/or” suggests that the two forms of DME might not be automatically conjoined; there could be cases in which need to install SER does not mean that FR is required also. This point is left hanging, though, in the PRC-002-2 Att. 1 methodology for selecting buses. The rules apply to, “SER and FR data,” together, not individually.

The issue is not clarified until one gets to the Rationale section of PRC-002-2, which confirms that there are SER-but-not-FR exceptions, “Generator step-up transformers (GSUs) and leads 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 are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.”

Talen Energy proposes that the FR exemption for GSUs and GSU-to-TO HV lines be stated in the Applicability section of PRC-002-3. The Rationale section of the standard should explain but not modify the Requirements section.

Likes 0	
Dislikes 0	

Response

“Comments received from Jamie Johnson – California ISO”
Question 1
☒ Yes

Question 2 (no additional comments)

“Comments received from Wayne Sipperly – NAGF”
Question 1
☒ **Yes**

Comments:
The NAGF supports the SAR project scope to ensure that sequence of events recording (SER), fault recording (FR) and dynamic Disturbance recording (DDR) devices are installed and periodically assessed for certain inverter-based resources (IBRs) thus providing adequate data to facilitate analysis of BES disturbances.

Question 2 (additional comments)
Comments:
Consider modifying the scope to add an implementation period for any newly identified BES buses. During five year reviews, new BES buses may be identified. DDR equipment may not already be on site and time is required for the design, procurement of material, and for installation.

The NAGF notes that the existing PRC-002-2 Rational section regarding R3 states that an FR exception exists for “Generator step-up transformers (GSUs) and leads 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”. This needs to be clarified with regard to PRC-002-2 Requirement 1. TOs should be required to send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

“Comments received from Pamela Hunter – Southern Company”
Question 1
☒ **No**

Comments:
Changes to the standard are not necessary for IBR facilities. Step 8 in Attachment 1 for R1 already provides a means by which bus locations not captured in the highest 10% bus fault current calculations are selected for SER and FR data monitoring to achieve the 20% total. Locations with Inverter Based Resources can be added to the list of required locations at the Transmission Owner’s discretion.

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Question 2 (additional comments)
Comments:
Modify the scope to add an implementation period for any newly identified BES buses. During five-year reviews, new BES buses may be identified. DDR equipment may not already be on site and time is required for the design, procurement of material, and for installation.

“Comments received from Daniel Gacek – Exelon”
Question 1
☒ No

Comments: While Exelon does not support the SAR in its current form, Exelon does support the concerns raised by the IRPTF regarding the need to place disturbance monitoring equipment (DME) closer to inverter-based resources (IBR). In addition to placing DME closer to IBRs, the specifications of the disturbance monitor equipment for IBRs will need to be developed to ensure data is sufficient to analyze system disturbances involving IBRs. The present PRC-002 methodology and disturbance monitoring equipment technical specifications, which is being implemented, serve conventional generation and buses remote from IBR well and those specifications should be preserved. Therefore, the SAR should be revised to specifically address the changes needed for IBR without altering the specifications for other resources.

Question 2 (additional comments)
Comments:
In the interest of system reliability and event analysis the responsible entities should be required to install DMEs in locations that would render the greatest amount of data for system analysis. For installations involving multiple IBRs that location may include an aggregation point such as the Point of Interconnection (POI) with the transmission system or transmission substation beyond the POI.

“Comments received from Brandon Gleason – ERCOT
☒ Yes

Comments: None

Question 2 (None)

Consideration of Comments

Project Name:	2021-04 Modifications to PRC-002-2 | Glencoe Light SAR
Comment Period Start Date:	6/14/2021
Comment Period End Date:	7/13/2021
Associated Ballots:	

There were 23 sets of responses, including comments from approximately 56 different people from approximately 50 companies representing 7 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, please 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, you can contact the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

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.

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
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
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		1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC

	Kim Thomas				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

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.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	No
Document Name	
Comment	
We believe that the notified interconnecting entity should have the FR/SER coverage on the notified BES Element(s) jointly owned by the interconnecting entities, which connect to the applicable bus owned by the notifying entity. We do not agree that the requirement calls for FR/SER monitoring on the lines, buses, transformers, and breakers on the bus owned by the notified entity, if the interconnecting BES element is only the line connecting to the bus owned by the notifying entity, as stipulated in the SAR proposal.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This comment appears to agree with the intent of the SAR, so the "No" vote is confusing. One of the SAR DT members reached out to commenting entity to clarify the intent of this SAR. The revised SAR states that the standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. This should clarify requirements for the Responsible Entities.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

The existing language of the standard defines only that the individual entities must provide notification and have data available. Under this language the entities are still free to collaborate in providing SER and FR data. The full submission from Glencoe Light and Power Goes on to stipulate: Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. Following this more prescriptive language recommended by Glencoe limits the opportunity for collaboration.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. One of the SAR drafting member explained in the BHE cross-platform meeting why this SAR was necessary and that it would not limit collaboration, only clarify required data. Among other things, one of the goal of this SAR is to revise the standard so that requirements are clear and that it eliminates unnecessary and administrative compliance burden for the Responsible Entities.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation would also recommend including more clarification on which party (BES bus owner or BES element owner) is responsible for installing FR and/or SER equipment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification.	
Thomas Foltz - AEP - 3,5,6	

Answer	Yes
Document Name	
Comment	
AEP agrees with the proposed scope, direction, and intended purpose and goals of the proposed SAR as drafted by Glencoe Light and Power. We recommend it be pursued, as we believe the effort would provide clarity and that the resulting efficiencies would benefit industry. While both the IRPTF SAR and the Glencoe Power and Light SAR each focus on revising PRC-002, their perceived needs and expressed goals are quite different. Because only one single SAR governs a project at any point in time, and because the unique efforts for the IRPTF SAR will likely be met with much more resistance than the Glencoe SAR, AEP recommends breaking this project into multiple phases, each with its own SAR governance. The Glencoe SAR will likely encounter less resistance from industry than the IRPTF SAR, so we recommend that the Glencoe SAR govern the first phase of the project. Once that phase is complete, the second phase could then begin with the IRPTF SAR governing Phase 2. Pursuing Project 2021-04 this way would be much more efficient, allowing progress to be made more quickly on the purpose and goal on the Glencoe SAR, and without potential delay associated to any resistance to efforts related to the IRPTF SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. SAR DT recommends a multi-phased approach with Glencoe Light SAR being addressed first.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The notification and data responsibility requirements in PRC-002 R1 and R3 needs clarification.	

When identifying BES buses for monitoring bus in this standard is defined as a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid. For the sake of this standard, the BES Elements identified for monitoring should be defined in the same way avoiding including BES Elements that are remote to the identified BES bus-like transmission lines and their remote terminals. The original intent of the standard drafting team was to make sure that the SER and FR data was available at the identified buses, so the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification. The revised SAR states that the standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. Clarification using these terms should also address clarifying elements local to the identified BES bus versus remote breakers.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
AZPS supports the scope of the SAR submitted by Glencoe Light.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
As noted by SAR written by Glencoe Light, the existing standard needs to be clarified as to whether it applies to directly connected versus remote buses indirectly connected. Pages 3 & 4 of the Glencoe Light SAR describe cases where ownership, notification, and compliance applicability for SER and/or FR data need to be clarified.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The revised SAR states that the standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements.	
William Steiner - Midwest Reliability Organization - 10	
Answer	Yes

Document Name	
Comment	

MRO agrees with the SAR that, in situations where the identified BES bus owner has the capability to measure and record the required FR data, the notification required by R1.2 and the possession of data required by R3 create compliance burdens for the entities subject to those requirements but may not be the best way to ensure that the data will be available for analysis. However, the solutions proposed in the SAR do not appear to ensure that the obligation to have data will be assigned clearly to one equipment owner. The SAR suggests that the owner of a BES Element connected to an identified BES bus should only be made responsible for having FR data in situations where the owner of the identified BES bus lacks the capability to obtain the data. This, however, would constitute a sort of cascading applicability scheme where the failure of one entity (the bus owner) to meet the data requirement would kick the obligation back to the connected BES Element owner. This approach seems difficult to enforce and does not fully mitigate the issue of uncooperative neighboring entities.

While not fully supportive of the proposed solutions in the SAR, MRO does support revision of the standard to mitigate the dependency of one equipment owner on another to meet the data possession requirement in R3. Other applicability schemes could likely be utilized to make the applicability of each requirement clear to all entities.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Some examples are added in the revised SAR to illustrate why standard should be revised to clarify the intent of R1.2 and R3. Revisions made to standard clarifying responsibilities for each entity would ensure that adequate FR and SER data is available for analysis.

Richard Jackson - U.S. Bureau of Reclamation - 1,5

Answer	Yes
Document Name	
Comment	

Reclamation recommends the owner of the required equipment be the evaluating entity. Criteria to determine what Facilities require SER/FR and DDR equipment should be provided to remove ambiguity. Reclamation recommends the scope of the SAR also include the items described in the response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The criteria to determine which facilities require SER/FR and DDR data/equipment is provided in Attachment 1 (referred in R1.1) and R5 respectively. The evaluating entity for SER/FR data/equipment is Transmission Owner, an entity responsible for short circuit model which is necessary to evaluate based on criteria in the Attachment 1. The evaluating entity for R5 is Responsible Entity as defined in 4.1., entity with all necessary data needed for evaluation. Also, please refer to response to Question 2.	
Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute’s (EEI) response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI's comment.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes

Document Name	
Comment	
In general Capital Power (on behalf of Decatur Energy Center and other Group 80 MRRE assets) agrees with the proposed scope. Please see additional comments in response 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Also, please see response to question #2.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the concern identified in the Glencoe Light SAR that Requirement R1, Subpart 1.2 does not clearly identify under what conditions notified owners of BES Elements connected to BES busses, identified under Part 1.2 of PRC-002-2; are obligated to install sequence of events recording (SER) and fault recording (FR) equipment. Additionally, given the parallel posting of both the IRPTF and Glencoe Light SARs, consideration should be given to addressing these two SAR under a single project but through a multi-phased approach with the Glencoe Light scope SAR being addressed in the first phase.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support. SAR DT recommends a multi-phased approach, with Glencoe Light SAR likely being addressed first.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
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	
David Jendras - Ameren - Ameren Services - 1,3,6	
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 Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
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	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA supports the project scope to modify Requirement R1, Part 1.2 to clarify notifications – it's been unclear both what to expect in return when we send out a notification as well as what to do with a notification when we receive one. Because of this, we have done SER and DFR	

reviews on stations that were identified to us by other entities on top of completing reviews of our PRC-002-2 identified stations. More clarity is needed on what specifically must happen when you receive a notification. The standard also states that the owner must supply the data upon request, but BPA has worked with other utilities to ensure we don't have gaps. There needs to be some leeway on allowing two or more utilities to have a formal, pre-established agreement if they choose to do so. It helps save utilities on cost if they can.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support. The SAR DT will recommend that the standards drafting team consider providing this clarification.	

2. Provide any additional comments for the SAR drafting team to consider, if desired.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

While Texas RE generally supports the scope of the proposed SAR and the overall intent of the proposed project, Texas RE proposes two additional areas for consideration in the upcoming project to improve the proposed PRC-002 Standard's overall effectiveness. First, the SDT should move periodic requirements set forth in the PRC-002 Implementation Plan directly in the Standard Requirement language contained in PRC-002-2 R1.3. Second, the SDT should review the "Median Method Excel Workbook" for potential anomalies. Texas RE provides additional details on each of these items below.

Periodic Requirements in the PRC-002-2 Implementation Plan

Texas RE is concerned there is a periodic requirement in the Implementation Plan for PRC-002-2, rather than in the requirement itself. Consistent with Standard Processes Manual, Section 4.4.3, implementation plans are intended to describe the proposed effective date, identify new or modified definitions, specify any prerequisite actions that need to be accomplished before entities are held responsible for compliance with the requirements, describe whether any conforming changes to other Reliability Standards will occur, and finally the Functional Entities that will be required to comply with the requirements.

In contrast to these core implementation plan elements, the PRC-002-2 implementation plan sets forth an explicit compliance periodicity that is not solely associated with registered entities' transition to compliance with the PRC-002-2 requirements. In particular, PRC-002-2, R1.3 states that TOs shall "re-evaluate buses at least once every five years and notify other owners…***and implement the re-evaluated list of BES buses as per the Implementation Plan.***" The current PRC-002-2 implementation plan in turn provides that "Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible

Entity that re-evaluated that list." When read together, therefore, the PRC-002-2 Registered Entities must continue to reference the current PRC-002-2 implementation plan in order to understand the requirement to implement the re-evaluated list of BES buses on a three-year cycle.

Texas RE recommends moving the three-year requirement from the PRC-002-2 implementation plan to the requirement language itself, as it is essentially a periodic requirement for TOs and is no longer associated with the prerequisite actions that need to be accomplished before Registered Entities are held responsible for PRC-002-2 R1.3. Such a change will provide additional clarity to registered entities as well as reduce the number of extraneous documents needed to comply with the standard.

Workbook Anomalies

In addition to explicitly incorporating the three-year BES bus re-evaluation language directly into the PRC-002-2 R1.3 requirement language, Texas RE also recommends the drafting team conduct a general re-evaluation of the "Median Method Excel Workbook" (located on the original project page) to ensure accurate evaluations. During the course of its ongoing compliance engagements, Texas RE staff discovered several potential anomalies and possible incorrect calculations throughout the Workbook. For example, Texas RE noticed the use of "SOER" (Sequence of Events Recording) within the Workbook, which had been removed from a Rationale dialog box in a May 2014 redline:

(https://www.nerc.com/pa/Stand/Project%20200711%20Disturbance%20Monitoring%20DL/PRC-002-2_Disturbance_Monitoring_2014May09_redline.pdf).

Texas RE staff also determined the same number of bus placements based on the example data but that number **differed** from the example provided within the Workbook. When using real world data, it was discovered that there may not be enough guidance to determine bus placement in a repeatable fashion as Workbook instructions appeared to not consider repeat values for three phase short circuit (e.g. multiple busses having the same short circuit values).

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR is revised to move periodic requirements set forth in the PRC-002 Implementation Plan in the standard as a requirement language. Review of "median method excel workbook" is not in the scope of this SAR. Revision to standard in response to IRPTF SAR may revise the methodology in attachment 1, and if so, SDT may review of the "median method excel workbook" and revise as necessary.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI looks forward to reviewing a future Project 2021-04 SAR, which contains elements of both SARs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Additionally, SAR DT recommends a multi-phased approach, with Glencoe Light SAR likely being addressed first.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	
Capital Power (on behalf of Decatur Energy Center and other Group 80 MRRE assets) appreciates any opportunity to reduce the administrative burden related to certain Reliability Standards. However, in this case, the notification of only the impacted entities may result	

in instances where, due to an administrative error, a potentially in-scope entity is not notified and assumes it is out of scope because no notification was received. To mitigate this risk, Capital Power recommends one of the following solutions: • Comprehensive, easily accessible list of all in-scope buses as well as what data is required ○ This will allow all entities, including those who may not have received a direct notification, to ensure that the lack of notification was not due to an administrative error ○ Ideally this list should be stored and/or facilitated on/via a centralized system such as NERC's Align system. • Positive confirmation of out of scope – TOs should notify all entities of their in-scope or out of scope status • Develop selection criteria specific to generators (inclusive of synchronous and inverter-based resources). Based on these criteria generators would be accountable and have the mechanism to make their own determination re. which assets require SER and FR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In regards to R1, TO is in ideal position to develop a list of buses in scope. If not notified by TO, then R2 and R3 does not apply and hence there is no risk of non-compliance. R2 and R3 includes details of data. The SAR DT does not agree that list of in-scope buses should be stored/facilitated via a centralized system such as NERC's align system. Requiring TOs to notify entities whose BES elements are not in scope of R1 is unnecessary burden on the TO. Criteria inclusive of sychornous and inverter-based resources is outside the scope of this SAR. The impact of growing penetration of IBRs is addressed by the NERC IRPTF SAR.	
Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	

Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI's comment.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
In general PRC-002 is loosely written. BPA has submitted questions to WECC for clarification. R4.3 states "Trigger settings for at least the following: 4.3.1 Neutral (residual) over current. 4.3.2 Phase undervoltage or overcurrent"; this can be interpreted that the XFMR can have a phase undervoltage trigger even though R3 states: "3.1 phase- to neutral voltage for each phase of each specified BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1 Transformers that have a low-side operating voltage of 100kV or above. 3.2.2 Transmission Lines."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. R4.3 specifies trigger settings to record electrical quantities specified in R3. The SAR DT feels these comments are not in scope for this SAR effort. The Guideline section for R4 provides some clarification for the triggering minimum requirements. The	

drafting team feels this is sufficient at this time, however the standard does not restrict owners from employing other triggering mechanisms in addition to the minimum requirements.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	
Reclamation recommends the PRC-002 SAR include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items: • In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators. • Requirement R1.3 should be modified to state the timeframe within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO). • Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list. • Reclamation recommends adding the sharing of protection system data when requested by the entity performing the R1 evaluation. • Requirement R12 should be modified to add a required time limit within which to notify the Regional Entity(ies) of a failure of the recording capability. Regional Entities need to know as soon as the failure occurs or is discovered, not up to 90 days later.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. SAR is revised and recommends the Standard DT to consider adding Planning Coordination to the Western Interconnection Responsible Entities, if appropriate. The time limit for notified entity per R1.3 and R5.4 is included in the implementation plan. The implementation plan states that entities shall be 100 percent compliant within three (3) years following the notification. This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan. The SAR is revised to move the three-year requirement from the PRC-002-2 implementation plan to the standard as a requirement language itself. The SAR DT disagrees with recommendation to add the sharing of protection system data with entity performing R1 evaluation. Not sure why protection system data is necessary to do re-evaluation in R1.3. SAR DT disagrees with need to revise Requirement R12 to reduce allowable time from 90 day period. Although it does not take a long time to replace or fix failed equipment, 90 day time period is necessary for unforeseen circumstances. The regional entity is only needed to be informed with a corrective action plan for information in case responsible entity is audited and does not have data available from the location where equipment failed.	
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.	
Likes 0	
Dislikes 0	
Response	

William Steiner - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	

- MRO has noted that the standard is complicated and difficult to interpret. Proper interpretation requires a nuanced understanding of various terms including "BES bus", "BES Element", "connected", and "directly connected." These terms are defined by a combination of the NERC Glossary of Terms and the standard itself. The uses of these terms in the standard provide further insight into how the terms should be understood. A more straightforward approach to defining terms in the standard would likely help to clarify the locations where recording is required as well as the delineation of responsibilities for obtaining data.

- The SAR includes the statement "the current standard could be interpreted that generation, transformer and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus" and implies that this is somehow an unnecessary or undesirable interpretation. However, it is MRO's opinion that this is the proper interpretation as R3 does not dictate the exact location of current measurement, only that the entity must have current data for the applicable transmission lines and transformers. If, for some reason, the only location where current sensing and recording equipment was installed was at the remote end of a transmission line or transformer, it would make sense to utilize that equipment rather than require installation of new equipment nearer to the identified BES bus.

- Clarifications regarding the current version of the standard and MRO’s interpretation:

  - R1.2 notifications do not obligate entities to have data, only R3 does that. The notifications ensure that BES Element owners with R3 obligations are aware of those obligations. An overreaching notification from the identified BES bus owner to an adjacent owner of equipment that does not meet the criteria given in R3 would not create any compliance obligation for the adjacent owner.

  - R1.2 and R3 are consistent with each other in addressing BES Elements "connected to the BES buses identified in Requirement R1."

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. SAR is revised and now states that terms such as such as "connected" and "directly connected" BES Elements should be clarified and as necessary, ensure consistent usage of terms such as "BES bus" and "BES Element" in the standard. Some examples are added in the revised SAR to illustrate why standard should be revised to clarify the intent of R1.2 and R3.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
Process question, with two different SAR write-ups (IRPTF from June 2020 and Glencoe Light from April 2021) out for comment, would the Standards Committee assign one SDT to both of these SARs or would the SARs be combined into one SAR?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. SAR DT recommends a multi-phased approach, with Glencoe Light SAR likely being addressed first.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

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

The proposal by Glencoe light does not address following issues, which should be addressed by the Standards Drafting Team on Requirement R1.

- The Requirement R1.2 obligates the notifying entity to notify the interconnecting entity about the FR or SER monitoring requirement on the interconnecting BES element(s) within 90 days of the determination of the BES buses. But it does not say anything about the obligation of the notified interconnecting entity in terms of time limits on their response or confirmation about implementing the FR/SER monitoring. There is provision to notify interconnecting FR/ER monitoring for the interconnecting BES element(s), but thereafter standard leaves it open. There is no follow-up on actual implementation of the FR/SER monitoring. The requirement should set some time limit on the notified entity to confirm/ or resolve issues if any towards implementing the FR/SER requirement. It should also address issues, when the applicable buses list of the notified interconnecting entity does not include the bus to which the interconnecting BES element in question is connecting.

- In the requirement R5, the Reliability Coordinator (RC) notifies the entities about DDR requirement. The RC should provide more details with the notification. Currently the RC notification merely includes the requirement no in the columns. It does not include why or how the requirement number was applied. For example If a notification of DDR monitoring goes to an entity under R5.1.5 (UVLS) or 5.1.2 (Stability of System Operating limits), then the standard does not clarify RC responsibility to notify other participating entities. The RC notification does not provide the details. What about the FR/SER monitoring requirement on those interconnections between entities if the buses do not figure in the 20% applicable buses list of the concerned entities?). The standard should address this.

• The requirement R1.1 should address step 8 of the algorithm in attachment 1 of the standard. For example, step 8 does not necessarily include the case of growing inverter-based resource monitoring. It has been noticed that while applying step 1-step7, the applicable buses tend to concentrate in the high MVA zones and distributed monitoring across the network does not occur. The standard or the algorithm need to be tweaked to address this issue.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The time limit for notified entity is in the implementation plan. This is also true for re-evaluated list from R1 and R5, where the implementation plan states that entities shall be 100 percent compliant within three (3) years following the notification. This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan. The SAR is revised to move the three-year requirement from the PRC-002-2 implementation plan to the standard as a requirement language itself. The SAR DT recognizes that details might be helpful to notified entity. However, Requirements R6, R7 and R8 are regardless of a reason (UVLS, SOLs etc.) for which entity is notified by the Responsible Entity to have DDR data. Hence, it is not necessary to require the notifying entity to provide details. The impact of growing penetration of IBRs is addressed by the NERC IRPTF SAR.	
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	
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	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comment. The SAR DT will recommend that the standards drafting team consider providing this clarification.	

"Comments received from Jamie Johnson – California ISO"
Question 1
☒ Yes

Comments: Any clarifications to the scope of NERC registered entities responsibilities promote clarity and add to reliability activities.

Response: Thank you for your comment and support. The intent of this SAR is to provide clarity for responsible entities. The SAR DT will recommend that the standards drafting team consider revision such that responsibilities for all entities is clearly stated.

Question 2 (no additional comments)

"Comments received from Wayne Sipperly – NAGF"
Question 1

☒ **Yes**

Comments:
The NAGF agrees with the proposed scope to clarify the notification and data responsibility requirements in PRC-002 R1 and R3. The BES Elements identified for monitoring should be defined as “a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid” to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Where the intent is to ensure that the SER and FR data is available at the identified buses, the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers

Response: Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification. The revised SAR states that the standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. Clarification using these terms should also address clarifying elements local to the identified BES bus versus remote breakers.

Question 2 (additional comments)
Comments:
PRC-002 R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.

The NAGF notes that the existing PRC-002-2 Rational section regarding R3 states that an FR exception exists for “Generator step-up transformers GSUs) and leads 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”. This needs to be clarified with regard to PRC-002-2 Requirement 1. TOs should be required to send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

Response: Thank you for your comment. Some examples are added in the revised SAR to illustrate why standard should be revised to clarify the intent of R1.2 and R3. The revised SAR states that obligation for FR data per requirement R3 needs clarification as to if the Generator

Owner is required or not to have FR data with examples shown in figures 7 and 8. Depending on clarification of this, the notification requirement in R1.2 may be revised and one alternative is to require TO to send separate SER and FR notifications.

“Comments received from Pamela Hunter – Southern Company”
Question 1
☒ **Yes**

Comments:
The notification and data responsibility requirements in PRC-002 R1 and R3 needs clarification.

The BES Elements identified for monitoring should be defined as “a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid” to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Where the intent is to make sure that the SER and FR data is available at the identified buses, the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers.

Response: Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification. The revised SAR states that the standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. Clarification using these terms should also address clarifying elements local to the identified BES bus versus remote breakers.

Question 2 (additional comments)
Comments:
R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.

The usual order of precedence for NERC standards is that the Rationale section only explains the requirements and does not modify them.

PRC-002-2 breaks this rule by treating SER and FR in a one-size-fits-both fashion in R1, then saying in the Rationale section that an FR exception exists for, ‘Generator step-up transformers (GSUs) and leads 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.’ It is awkward to have a letter from the TO saying that FR is required, and having to point-out to auditors that the Rationale section of PRC-002-2 overrules. PRC-003-3 should have TOs send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

Response: Thank you for your comment. Some examples are added in the revised SAR to illustrate why standard should be revised to clarify the intent of R1.2 and R3. The revised SAR states that obligation for FR data per requirement R3 needs clarification as to if the Generator Owner is required or not to have FR data with examples shown in figures 7 and 8. Depending on clarification of this, the notification requirement in R1.2 may be revised and one alternative is to require TO to send separate SER and FR notifications.

“Comments received from Daniel Gacek – Exelon”
Question 1
☒ **Yes**

Comments: Exelon agrees that the BES element owner should be responsible for data required for PRC-002-2. The BES Elements identified for monitoring should be defined as “a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid” to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Response: Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification. The revised SAR states that the standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. Clarification using these terms should also address clarifying elements local to the identified BES bus versus remote breakers.

Question 2 (additional comments)
Comments:
Receiving notifications from a TO that data is not required for a BES Element is beneficial and such notifications should not be eliminated by changes to the standard.

Response: Thank you for your comment. Notifications when SER/FR/DDR data is not required places an unnecessary administrative compliance burden on the Responsible Entity. One of the goal of this SAR is to revise the standard to eliminate unnecessary and administrative compliance burden for the Responsible Entities.

Consideration of Comments

Project Name:	2021-04 Modifications to PRC-002-2 | IRPTF SAR
Comment Period Start Date:	6/14/2021
Comment Period End Date:	7/13/2021
Associated Ballots:	

There were 23 sets of responses, including comments from approximately 50 different people from approximately 44 companies representing 7 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, please 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, you can contact the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

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.

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
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

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.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS does not support the scope of the SAR submitted by the NERC Inverter-based Resource Performance Task Force (IRPTF) because is too broad and does not provide specific information on the changes to be addressed by the standard drafting team. Additionally, AZPS does not agree that the IRPTF White Paper provides sufficient justification for revising the standard. AZPS's experience has shown that any significant inverter based resources tie into large substations for which the MVA requirement would cover the need for monitoring.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Despite, commenters disagreement the SAR and IRPTF white paper has been vetted by NERC IRPTF, RSTC and has broad support within the industry. APS's experiences are not necessarily indicative of many other BES areas.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	

The City of Tallahassee (TAL) believes that requiring additional monitoring equipment is not cost-effective given the minor contribution to the BES in terms of fault current. TAL is unsure how the data collected will provide a substantial gain to the BES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Four event reviews have been documented stating additions and revisions to monitoring requirements are needed. The criteria in Attachment 1 and R5 for SER/FR and DDR data respectively mostly excludes all IBRs.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA disagrees with this project scope. PRC-002-2 Attachment 1, Step 8 already says “the additional BES buses are selected, at the Transmission Owner’s discretion, to provide maximum wide-area coverage for SER and FR data.” It then provides recommendations for selecting additional bus locations. We do not only rely on PRC-002-2 to require disturbance monitoring and recording. We have our own requirements for when to install disturbance monitoring and recording and the TO should know their system well enough to know when and where they need to monitor. In order to completely eliminate the possibility of not having data available for event analysis, you’d have to require monitoring and recording at every substation which may or may not be possible. The SAR mentions the IBRs don’t provide enough fault current, thus they can contribute to a fault. PRC-002 is for wide area faults and reconstructing them. This SAR may be better applied to PRC-023 or another protection standard. The owners need to update their own standards for SER/FR equipment or at least protective systems (most offer both limited SER/FR capability).	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Attachment 1, Step 6 limits the majority of IBR connections. Step 8 follows the limitations of step 6. The goal of SAR is not to require data for all possible events but to ensure that PRC-002 takes into account large IBR penetration in low short circuit MVA areas and address possible additional GO requirements that apply to IBRs. Not sure how revising PRC-023 or another protection standard addresses needs identified in this SAR. Additional comments addressed by Glencoe SAR (Duplicate of commenters comments submitted for Glencoe SAR)

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
No 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	

Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	

AEP believes there may be benefit in pursuing this SAR, however we do not believe that the burden to install SER, FR, and DDR should be placed on the Transmission Owner. Rather, any such obligations to do so should be placed solely on the Generator Owner of those resources.

We believe Attachment One should be revised to make it absolutely clear that it governs Transmission assets only. Generation resources deserve their own distinct selection criteria for R1 and R3, one that is inclusive of both synchronous generation and inverter based generation. Generator Owners should be able to make their determination on which assets require FR and SER solely on the resource in question, and not based on analysis regarding how that asset is compared to others. One suggested method to consider would be establishing individual and aggregate thresholds for when SER and FR would need to be installed.

While both the IRPTF SAR and the Glencoe Power and Light SAR each focus on revising PRC-002, their perceived needs and expressed goals are quite different. Because only one single SAR governs a project at any point in time, and because the unique efforts for the IRPTF SAR will likely be met with much more resistance than the Glencoe SAR, AEP recommends breaking this project into multiple phases, each with its own SAR governance. The Glencoe SAR will likely encounter less resistance from industry than the IRPTF SAR, so we recommend that the Glencoe SAR govern the first phase of the project. Once that phase is complete, the second phase could then begin with the IRPTF SAR

governing Phase 2. Pursuing Project 2021-04 this way would be much more efficient, allow progress to be made more quickly on the purpose and goal on the Glencoe SAR, and without potential delay associated to any resistance to efforts related to the IRPTF SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support. Comments appropriate for standard drafting team and will be passed to the standard drafting team. SAR DT recommends a multi-phased approach, with Glencoe Light SAR likely being addressed first.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Step 8 in Attachment 1 for R1 already provides a means by which bus locations not captured in the highest 10% bus fault current calculations are selected for SER and FR data monitoring to achieve the 20% total. Locations with Inverter Based Resources can be added to the list of recommended locations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Attachment 1, Step 8 follows the limitations of step 6 which would eliminate most IBR facilities. Additional comments in response to Question #2 to be covered by the Glencoe SAR.	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	
The rationale for R1 on page 22 explains in detail the data analysis efforts which have gone into developing a methodology for identifying optimum number of buses. The study established a strong correlation between the short circuit MVA level available at a bus and its relative size based on voltage level, no. of transmission lines and other BES elements connected have an impact on system reliability. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment. Though entities could cover the inverter-based resources under optional buses in Step 8 of the algorithm in attachment 1 of the standard.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Attachment 1, Step 8 follows the limitations of step 6 which would eliminate most IBR facilities. Observation is correct that attachment 1, steps 1 through 7 leads to list of buses with high SC MVA zone. The algorithm in attachment 1 might be tweaked by the SDT. The focus of SAR DT is on the justification to revise the standard. The requirement for TO/GO for DDR is regardless of a reason for which DDR is required under R5. It would be nice if RC provides details justifying a need of DDR, however, the SAR DT believes that is not required to be addressed by the standard. Comments to be forwarded for consideration by Standard drafting team.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
The existing standard targets BES elements with short circuit MVA in the top 20% which could leave out inverter-based resources. Recent events involving inverter-based resources (IBR), such as the Blue Cut Fire and Canyon 2 Fire, have demonstrated the need to monitor some inverter-based resources. The Project 2021-04 SAR (the portion written by the IRPTF) addresses the need to monitor some IBRs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	

Reclamation agrees with the addition of a requirement to further enhance SER/FR and DDR equipment in facilities on the premise that the information obtained not only enhances BES reliability but also enhances an entity's ability to troubleshoot and repair Facilities, further reduce operating costs, and increase reliability. Reclamation recommends the scope of the SAR also include the items described in the response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.	
Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Refer to response to EEI's comment.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	

Comment	
Capital Power (CP) (on behalf of Decatur Energy Center LLC and other MRRE group 80 assets) supports the NAGF submitted comments on this item.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comment.	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
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	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
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	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
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	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	

Comment	
EEI supports the concerns identified in the IRPTF SAR that current processes contained within PRC-002-2 (Attachment 1) used to identify BES buses where sequence of event (SER) and fault recording (FR) equipment are to be installed generally do not require the placement of this equipment on buses where IBR resources are prevalent. The SAR SDT should consider the potential fault recording differences that may be required by IBRs, such as the possible need for faster sampling rates for IBRs, while providing little value for synchronous resources. EEI also suggests SER and FR equipment might be efficiently placed at the point of aggregation where this information would be more useful. Additionally, given the parallel posting of both the IRPTF and Glencoe Light SARs, consideration should be given to addressing these two SAR under a single project but through a multi-phased approach with the Glencoe Light scope SAR being addressed in the first phase.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Details of where the DME is placed and potential fault recording differences that may be required by IBRs (such as possible need for faster sampling etc.) to be addressed by the standard drafting team. Your comments will be passed on to the standard drafting team. SAR DT is considering a multi-phased approach, with Glencoe Light SAR likely being addressed first.	

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

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI looks forward to reviewing a future Project 2021-04 SAR, which contains elements of both SARs.

Likes 0	
Dislikes 0	

Response

Thank you for your support. Details of where the DME is placed and potential fault recording differences that may be required by IBRs (such as possible need for faster sampling etc.) to be addressed by the standard drafting team. Your comments will be passed on to the standard drafting team.

SAR DT is considering a multi-phased approach, with Glencoe Light SAR likely being addressed first.

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	
Document Name	

Comment

Capital Power (CP) (on behalf of Decatur Energy Center LLC and other MRRE group 80 assets) supports the NAGF submitted comments on this item.

In addition, CP supports Reclamation’s recommendation of the following (modified slightly):

PRC-002 SAR should include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items: • In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators. • Requirement R1.3 should be modified to state the timeframe / implementation period within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO). ○ This is particularly important when it comes to newly identified BES buses in remote areas where DDR equipment may not already be on-site and will need to be designed, procured, and installed. • Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list. • The addition of a requirement allowing exemption based on equipment limitation, age of asset etc. If a newly identified BES Bus happens to be connected to an existing asset nearing the end of its useful life, the cost / benefit of the installation of additional DDR equipment should be considered.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comment. Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.	
Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	
Answer	

Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Details of where the DME is placed and potential fault recording differences that may be required by IBRs (such as possible need for faster sampling etc.) to be addressed by the standard drafting team. Your comments will be passed on to the standard drafting team. SAR DT is considering a multi-phased approach, with Glencoe Light SAR likely being addressed first.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
In general, PRC-002 is loosely written. BPA has submitted questions to WECC for clarification. R4.3 states "Trigger settings for at least the following: 4.3.1 Neutral (residual) over current. 4.3.2 Phase undervoltage or overcurrent"; this can be interpreted that the XFMR can have a phase undervoltage trigger even though R3 states: "3.1 phase- to neutral voltage for each phase of each specified BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1 Transformers that have a low-side operating voltage of 100kV or above. 3.2.2 Transmission Lines."	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Attachment 1, Step 6 limits the majority of IBR connections. Step 8 follows the limitations of step 6.

The goal of SAR is not to require data for all possible events but to ensure that PRC-002 takes into account large IBR penetration in low short circuit MVA areas and address possible additional GO requirements that apply to IBRs.

Not sure how revising PRC-023 or another protection standard addresses needs identified in this SAR.

Additional comments addressed by Glencoe SAR

(Duplicate of commenters comments submitted for Glencoe SAR)

Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	

Reclamation recommends the PRC-002 SAR include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items:

- In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators.
- Requirement R1.3 should be modified to state the timeframe within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO).
- Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.

- Reclamation recommends adding the sharing of protection system data when requested by the entity performing the R1 evaluation.
- Requirement R12 should be modified to add a required time limit within which to notify the Regional Entity(ies) of a failure of the recording capability. Regional Entities need to know as soon as the failure occurs or is discovered, not up to 90 days later.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.

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

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Despite, commenter’s disagreement the SAR and IRPTF white paper has been vetted by NERC IRPTF, RSTC and has broad support within the industry.

APS's experiences are not necessarily indicative of many other BES areas.

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

Answer	
Document Name	
Comment	

The proposal from IRPTF does not address following issues, which the Standards Drafting Team (SDT) should consider.

- The requirement R1.1 should address step 8 of the algorithm in attachment 1 of the standard. For example, step 8 does not necessarily include the case of growing inverter-based resource monitoring. It has been noticed that while applying step 1-step7, the applicable buses tend to concentrate in the high MVA zones and distributed monitoring across the network does not occur. The standard or the algorithm need to be tweaked to address this issue.

- The algorithm could adopt the weighted points technique considering MVA, Voltage, NO. of lines, IROL (Interconnection Reliability Operating Limit) and SOL (Stability Operating Limit), UVLS schemes, and Vegetation parameters to derive a distributed FR/SER/DDR monitoring.

- Standard should address follow through action by notified entities participating in interconnection with the notifying entity in a time bound way to ensure adequate FR/SER/DDR monitoring in zones, where multiple entities are involved. DDR notification by Reliability Coordinators (RC) should have more details justifying the DDR requirement than merely quoting the requirement nos. in the notification document.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Attachment 1, Step 8 follows the limitations of step 6 which would eliminate most IBR facilities.

Observation is correct that attachment 1, steps 1 through 7 leads to list of buses with high SC MVA zone. The algorithm in attachment 1 might be tweaked by the SDT. The focus of SAR DT is on the justification to revise the standard.

The requirement for TO/GO for DDR is regardless of a reason for which DDR is required under R5. It would be nice if RC provides details justifying a need of DDR, however, the SAR DT believes that is not required to be addressed by the standard. Comments to be forwarded for consideration by Standard drafting team.	
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	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
N/A	
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 to add an implementation period for newly identified BES buses. During five year reviews, new BES buses are identified, and particularly in the case of BES buses like ones that may be identified as a result of this SAR that are interconnected at remote areas of the system, DDR equipment may not already be on-site and will need to be designed, procured, and installed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Additional comments in response to Question #2 to be covered by the Glencoe SAR.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	

Answer	
Document Name	
Comment	

PRC-002-2 says in Requirement R1.2 that TOs shall, “Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.” The expression “and/or” suggests that the two forms of DME might not be automatically conjoined; there could be cases in which need to install SER does not mean that FR is required also. This point is left hanging, though, in the PRC-002-2 Att. 1 methodology for selecting buses. The rules apply to, “SER and FR data,” together, not individually.

The issue is not clarified until one gets to the Rationale section of PRC-002-2, which confirms that there are SER-but-not-FR exceptions, “Generator step-up transformers (GSUs) and leads 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 are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.”

Talen Energy proposes that the FR exemption for GSUs and GSU-to-TO HV lines be stated in the Applicability section of PRC-002-3. The Rationale section of the standard should explain but not modify the Requirements section.

Likes 0	
Dislikes 0	
Response	

Thank you for your support.

Additional comments provided with response to Question 2 will be forwarded to standard drafting team for consideration and falls in scope of the Glencoe SAR.

“Comments received from Jamie Johnson – California ISO”
Question 1

☒ Yes

Question 2 (no additional comments)

"Comments received from Wayne Sipperly – NAGF"
Question 1
☒ **Yes**

Comments:
The NAGF supports the SAR project scope to ensure that sequence of events recording (SER), fault recording (FR) and dynamic Disturbance recording (DDR) devices are installed and periodically assessed for certain inverter-based resources (IBRs) thus providing adequate data to facilitate analysis of BES disturbances.

Response: Thank you for your support and comment.

Question 2 (additional comments)
Comments:
Consider modifying the scope to add an implementation period for any newly identified BES buses. During five year reviews, new BES buses may be identified. DDR equipment may not already be on site and time is required for the design, procurement of material, and for installation.

The NAGF notes that the existing PRC-002-2 Rational section regarding R3 states that an FR exception exists for "Generator step-up transformers (GSUs) and leads 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". This needs to be clarified with regard to PRC-002-2 Requirement 1. TOs should be required to send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

Response: Thank you for your support and comment. Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.

"Comments received from Pamela Hunter – Southern Company"

Question 1
☒ **No**

Comments:
Changes to the standard are not necessary for IBR facilities.   Step 8 in Attachment 1 for R1 already provides a means by which bus locations not captured in the highest 10% bus fault current calculations are selected for SER and FR data monitoring to achieve the 20% total. Locations with Inverter Based Resources can be added to the list of required locations at the Transmission Owner's discretion.

Response: Thank you for your comment. Attachment 1, Step 6 limits the majority of IBR connections. Step 8 follows the limitations of step 6.

Question 2 (additional comments)
Comments:
Modify the scope to add an implementation period for any newly identified BES buses. During five-year reviews, new BES buses may be identified. DDR equipment may not already be on site and time is required for the design, procurement of material, and for installation.

Response: Thank you for your comment. Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.

"Comments received from Daniel Gacek – Exelon"
Question 1
☒ No

Comments: While Exelon does not support the SAR in its current form, Exelon does support the concerns raised by the IRPTF regarding the need to place disturbance monitoring equipment (DME) closer to inverter-based resources (IBR). In addition to placing DME closer to IBRs, the specifications of the disturbance monitor equipment for IBRs will need to be developed to ensure data is sufficient to analyze system disturbances involving IBRs.   The present PRC-002 methodology and disturbance monitoring equipment technical specifications, which is being implemented, serve conventional generation and buses remote from IBR well and those specifications should be preserved. Therefore, the SAR should be revised to specifically address the changes needed for IBR without altering the specifications for other resources.

Response: Thank you for your comment. Commenter appears to agree with the spirit of the SAR but voted no due to lack of specificity in the SAR. However, the SAR has been vetted by NERC IRPTF, RSTC and has broad support within NERC and the industry.

The SARS intention is not to make significant changes to conventional generation requirements and is directed towards specifically addressing the integration of IBR's in the BES.

The SAR's lack of more detailed specificity is to allow the standard drafting team leeway to evaluate solutions based on NERC reports and the drafting of IEEE P2800.

Question 2 (additional comments)
Comments:
In the interest of system reliability and event analysis the responsible entities should be required to install DMEs in locations that would render the greatest amount of data for system analysis. For installations involving multiple IBRs that location may include an aggregation point such as the Point of Interconnection (POI) with the transmission system or transmission substation beyond the POI.

Response: Thank you for your comment. Commenter appears to agree with the spirit of the SAR but voted no due to lack of specificity in the SAR. However, the SAR has been vetted by NERC IRPTF, RSTC and has broad support within NERC and the industry.

The SARS intention is not to make significant changes to conventional generation requirements and is directed towards specifically addressing the integration of IBR's in the BES.

The SAR's lack of more detailed specificity is to allow the standard drafting team leeway to evaluate solutions based on NERC reports and the drafting of IEEE P2800.

Additional comments will be forwarded to Standard Drafting Team.

“Comments received from Brandon Gleason – ERCOT
☒ Yes

Comments: None

Question 2 (None)

Unofficial Nomination Form

Project 2021-04 Modifications to PRC-002-2

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Friday, July 30, 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.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

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.

Modifications to PRC-002-2

The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The "IRPTF Review of NERC Reliability Standards White Paper" was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed.

The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR) data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES).

In addition, Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data and implicitly obligates these transformer or transmission line BES Element owners to either:

1. work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on for compliance, or
2. the transformer or transmission line BES Element owner must install its own equipment that is duplicative to the identified BES Bus recording equipment.

The goal of the proposed project is to clarify the necessary notifications in Requirement R1, Part 1.2 relative to FR data, and clearly identify the BES Element owners that need to have FR data for transformers and transmission lines with the associated identified bus.

Standards affected: PRC-002-2

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-002.

Name:	
Organization:	
Address:	
Telephone:	
Email:	

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[1] 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	

[1] 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:		Email:	
Name:		Telephone:	
Organization:		Email:	
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:	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

UPDATED
Standards Announcement
Project 2021-04 Modifications to PRC-002-2

Nomination Period Now Open through July 30, 2021

Now Available

Nominations are being sought for Standard Authorization Requests (SARs) drafting team members. The due date has been extended, and is now open through **8 p.m. Eastern, Friday, July 30, 2021**.

Use the electronic form to submit a nomination. Contact Linda Jenkins regarding issues using the electronic form. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

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-002.

Previous drafting or review team experience is beneficial, but not required. See the project page and nomination form for additional information.

Next Steps
The Standards Committee is expected to appoint members to the SAR drafting team in August 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 2021-04 Modifications to PRC-002-2” 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

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	April 8, 2021 (Revised on November 16, 2021)		
SAR Requester			
Name:	Terry Volkmann (Revised by Project 2021-04 SAR Drafting Team)		
Organization:	Glencoe Light and Power NCR11444		
Telephone:	612-419-0672	Email:	terrylvolkmann@gmail.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The purpose of PRC-002-2[1] is to have adequate sequence of events recording (SER) and fault recording (FR) data available to facilitate analysis of Bulk Electric System[2] (BES) disturbances. Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data andimplicitly obligates these transformer or transmission line BES Element owners to either:			

[1] NERC Reliability Standard PRC-002-2 Disturbance Monitoring and Reporting Requirements (https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&Jurisdiction=United%20States) .

[2] See Glossary of Terms Used in NERC Reliability Standards (https://www.nerc.com/files/glossary_of_terms.pdf).

Requested information
1. Work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on forcompliance, or 2. Install its own equipment that isduplicative to the identified BES Bus recording equipment. Below is Requirement R1 for reference: **R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-termPlanning] **1.1.** Identify BES buses for which sequence of events recording (SER) and fault recording(FR) data is required by using the methodology in PRC-002-2, Attachment 1. **1.2.** Notify other owners of BES Elements connected to those BES buses, if any, within90-calendar days of completion of Part 1.1, that those BES Elements **require** SER dataand/or FR data. **1.3.** Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement there-evaluated list of BES buses as per the Implementation Plan. Notifications for FR data are being sent to BES Element owners that extend well beyond the BES bus boundary described in PRC-002-2 Attachment 1 as “a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid.” Notifying BES Element owners beyond this boundary unnecessarily obligates the BES Element (i.e., transformer or transmission line) owner to Requirement R3, including joint owners. The PRC-002-2 implementation plan states “Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 and R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated the list.” This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan. Moving the three-year requirement from the PRC-002-2 implementation plan to the standard as a requirement language itself will provide clarity to Responsible Entities. Requirement R1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with R1.1. Depending on results of this re-evaluation, location at which SER/FR data is required could change due to minor change in three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on methodology in Attachment 1. The standard currently does not give any guidance on what is considered a substantial change in three phase short circuit MVA. Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations would help with associated cost and compliance burden. If appropriate, add Planning Coordinator to the Western Interconnection in Section 4.1.3 as a Responsible Entity.

Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal of the proposed project is to: • Clarify the necessary notifications in Requirement R1, Part 1.2 relative to the SER/FR data, and clearly identify the BES Element owners that need to have SER/FR data for transformers and transmission lines with the associated identified bus. • Move requirement to be 100 percent compliant within three (3) years following notification of a re-evaluated list by the responsible entity from the implementation plan to the standard itself. • Add a criterion that constitutes a substantial change in fault current levels which would require changing SER/FR data recording locations. • If appropriate, add Planning Coordinator to the Western Interconnection in Section 4.1.3 as a possible Responsible Entity.
Project Scope (Define the parameters of the proposed project):
The scope should include: • Modifying Requirement R1, Part 1.2 to clarify notifications, which may include but is not limited to separating the notifications for SER data and/or FR data. Additionally, Requirement R3 should be modified so that it is abundantly clear to the applicable Transmission Owner and Generator Owner when their BES Element must have FR data for an applicable transformer or transmission line. • Clarifying various terms such as “connected” and “directly connected” BES Elements and as necessary, ensure consistent usage of terms such as “BES bus” and “BES Element” in the standard. • Codifying the three (3) year implementation period of newly identified buses in the re-evaluation performed per Requirement R1, Part 1.3 and R5.4 of the standard. The SDT should also clarify if this implementation period is three calendar years or three years from the notification from the responsible entity. • Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations. • If appropriate, adding Planning Coordinator to the Western Interconnection in Section 4.1.3 as a possible Responsible Entity.
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[3] 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 Transmission Owner (TO) applying the method in Attachment 1 who identifies a BES bus is in the ideal position to know which BES Elements (i.e., circuit breakers, transformer and transmission line) are connected to a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. Additionally, the identified BES

[3] 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
bus owner should know who owns the particular BES Element (i.e., circuit breaker) that needs SER and FR data to capture disturbances on generators, transformers, and transmission lines as identified in Requirement R3. Owners of BES Elements beyond the physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid should not be notified, unless their SER and FR data is needed to complete the identified BES bus SER and FR data. Requirement R1, Part 1.1 uses a method and BES bus definition[4] outlined in Attachment 1 to identify BES buses that requires SER data and/or FR data. Part 1.2 requires the notification of other BES Element owners connected to the identified BES bus under Requirement R1, Part 1.1. As currently written, a notification is required regardless of whether the identified BES bus owner has FR data for the intended BES Element (i.e., transformer or transmission line) or owns the BES Elements directly connected to the identified BES bus. Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. This will eliminate unnecessary notifications and obligations of the transformer and transmission line owners to compel other entities to have SER and FR data when there is no authority to do so. In these cases, the other BES Element owner(s) have to rely on SER and FR data from another entity that does not have the obligation under the standard. Additionally, clarifying the BES Element for which SER and FR data is required will reduce auditing needs resulting from notifying BES element owners who should not be responsible to have SER and FR data as well as reducing the cost burden of meeting the reliability need for SER and FR data. The standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. PRC-002-2 uses “connected” in Requirements R1.2 and R3, however, “directly connected” is used in Requirement R2. One interpretation of “connected” versus “directly connected” is shown in Figure 1, where all breakers are considered “directly connected” and other BES elements such as transmission lines, transformers and generators are “connected” to the bus. Figure 2 shows an example of a ring bus arrangement with possible classification of “connected” and “directly connected” BES elements.

[4] Attachment 1, Step 1: Determine a complete list of BES buses that it owns. For the purposes of this standard, a single **BES bus** includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Requested information

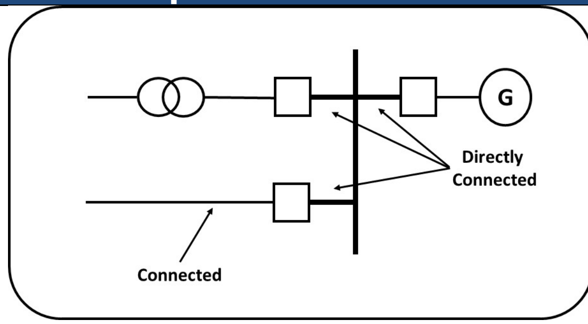


Figure 1

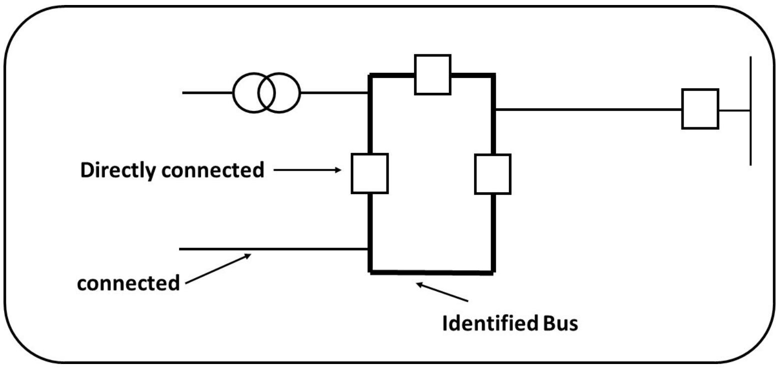


Figure 2

A straight bus configuration shown in Figure 3 is the simplest BES bus configuration sharing a common ground grid. Only the BES circuit breakers “1”, “2” and “3” are “directly connected” to the identified BES bus.

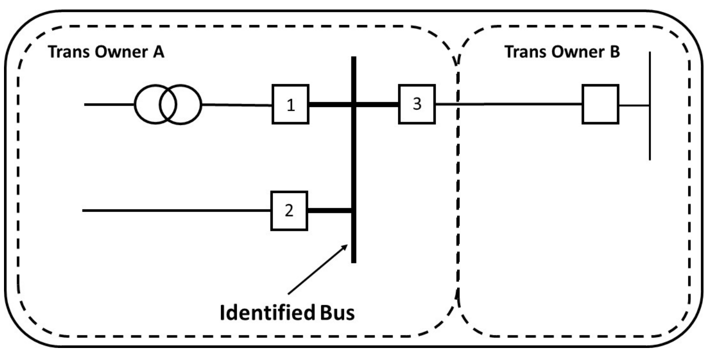


Figure 3

In this case, Transmission Owner A owns the BES bus as well as all breakers “directly connected” to it. In case where this BES bus is identified in Requirement R1, then Transmission Owner A is responsible for recording SER and FR data per Requirements R2 and R3 respectively. The Transmission Owner A should not be required to notify Transmission Owner B under Requirement R1.2 because Transmission Owner B does not own a BES element “directly connected” to the identified bus. However, per currently written Requirement R1.2, Transmission Owner A is required to notify Transmission Owner B. This has

Requested information
resulted in unnecessary notifications per Requirement R1.2 among various entities. The same is true for a ring bus configuration shown in Figure 4.

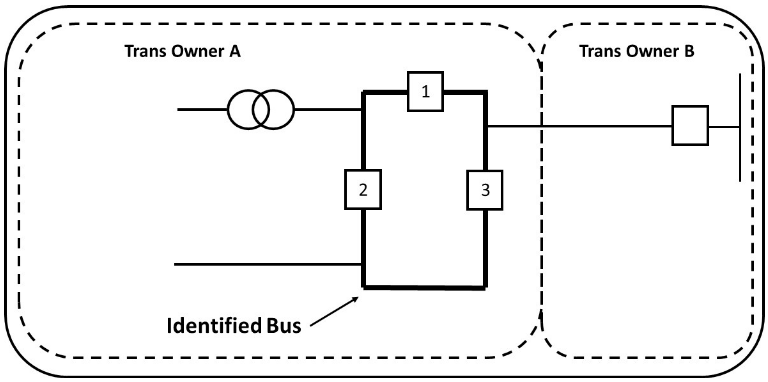


Figure 4

Figure 5 shows a variation of example in Figure 3, where BES breaker "3" is owned by Transmission Owner B. In this case, per Requirement R1.2, Transmission Owner A must notify Transmission Owner B that BES breaker "3" requires SER and FR data as breaker "3" is "directly connected" to the identified bus. In this case it is clear that SER data in Requirement R2 is required because the BES circuit breaker "3" is "directly connected" to the identified bus. Although Requirement R3 does not mention "directly connected", it is clear that Transmission Owner B is required to have FR data to determine specified electrical quantities for breaker "3". From there how the compliance requirement is met is up to the involved entities.

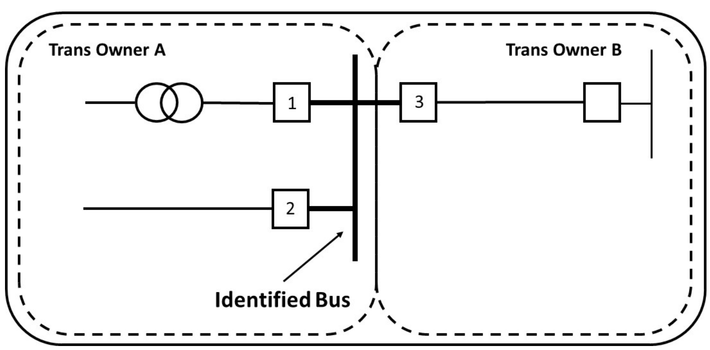
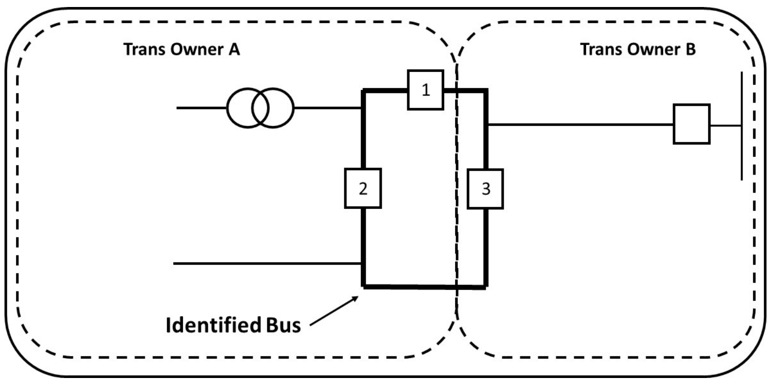


Figure 5

Under the current Requirement R1, Part 1.2, the identified BES bus owner is required to notify all owners of "directly connected" breakers that SER and/or FR data is required.

Under the current Requirement R3, the notified Transmission Owner B is required to have FR data, either by obtaining FR data from Transmission Owner A or by installing their own equipment. The Transmission Owner B cannot compel the Transmission Owner A to provide FR data. Additionally, relying on another entity for complying with PRC-002-2 places Transmission Owner B at risk if the other entity fails to have the necessary and adequate FR data.

Requested information
The intent of the standard in Requirement R3 is to have FR data associated with all applicable BES Elements at a single BES bus. This includes physical buses with breakers "directly connected" at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus. Requirement R1, Part 1.2 should only require notification to the BES Element (i.e., circuit breaker) owner "directly connected" with the identified BES bus. Under a ring bus configuration shown in Figure 6, elements (such as transmission lines, transformers etc.) that connect to the ring bus share BES circuit breakers for their protection system. The notifications per Requirement R1.2 by the identified bus owner are the same as with example in Figure 4. From there how the compliance requirement is met is up to the involved entities.  **Figure 6** If one of the connecting elements is a generator as shown in Figure 7, Requirement R2 is clear about SER data obligation for the Generator Owner and notification from Transmission Owner to Generator Owner per Requirement R1.2 should be required. However, obligation for FR data per requirement R3 needs clarification as to if the Generator Owner is required or not to have FR data for breaker "3". Requirement R3.2.1 exempts generator step-up transformers, implying that FR data would be available from equipment on the transmission system but this assumption may not be valid in all scenarios. The same clarification is also necessary for a configuration shown in Figure 8 where a generator is connected to the identified BES bus via a tie-line and the ownership of breaker "3" and the interconnecting tie-line belongs to the Generator Owner. From PRC-002-2 perspective, expectations for having FR data for breaker "3" is not different for scenarios presented in Figures 7 and 8.

Requested information

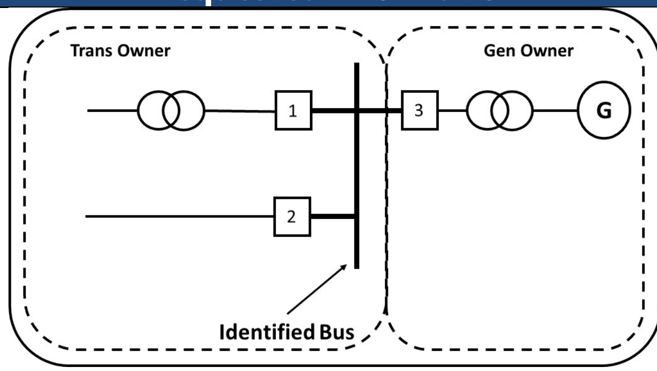


Figure 7

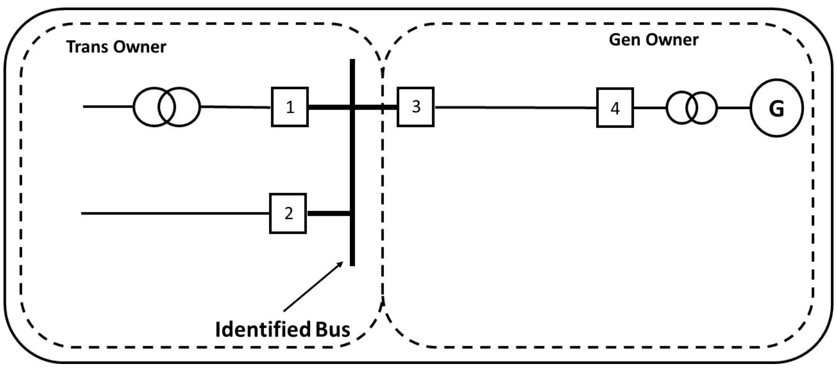


Figure 8

Identifying the appropriate BES Elements at the same voltage level within the same physical location sharing a common ground grid that requires SER and/or FR data will help facilitate obtaining data by only having to seek the data from those entities directly connected to the identified BES bus. However, the current standard could be interpreted that generation, transformer, and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus. As such, any modifications should consider alternative approaches that will achieve the intent of the standard while reducing associated cost and compliance burdens.

The PRC-002-2, R1.3 and R5.4 requires Responsible Entities to re-evaluate BES buses/BES Elements at least once every five calendar years and notify other owners…and implement the re-evaluated list of BES buses/BES Elements as per the Implementation Plan. The current PRC-002-2 implementation plan in turn requires that “Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated that list.” This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan in order to understand the requirement to implement the re-evaluated list of BES buses/BES Elements on a three-year cycle. Moving the three-year requirement from the PRC-002-2 implementation plan to the standard as requirement language itself, as it is essentially a periodic

Requested information
requirement, will provide additional clarity to Responsible Entities as well as reduce the number of extraneous documents needed to comply with the standard. Requirement R1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with R1.1, which refers to methodology presented in Attachment 1. Attachment 1, Step 7 specifies that if the list has one (1) or more but less than or equal to 11 buses the FR/SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in step 3. This is applicable to small Transmission Owners. During a re-evaluation, depending on minor system changes, it is likely that a bus with a highest maximum available three phase short circuit MVA changes and would require installation of equipment to capture SER/FR data at this newly identified bus. This is justified if change in fault currents is large, however, if the change is minor then results in unnecessary burden on the Responsible Entity. Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations would help with associated cost and compliance burden.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
For most part, the proposed modifications would eliminate unnecessary and administrative compliance burden for the Responsible Entities. If the revised standard requires disturbance monitoring equipment, approximate cost would be $50,000 to $100,000 per installation unless the existing equipment is set up for monitoring and storage.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The standard already applies to TOs and GOs but depending on revision, additional generator interconnecting facilities might be required to provide FR data.
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 and Generation Owner
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
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)?
A SAR was submitted by the NERC Inverter-Baser Resource Performance Task Force (IRPTF) to address potential gaps and improvements based on the work and findings of the IRPTF was authorized for posting by the NERC Standards Committee on January 20, 2021.

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

Requested information
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.
Standard Implementation Guide or Practice Guide could provide the necessary clarity; however, these documents cannot change the strict language of the PRC-002-2 Reliability Standard. Nothing is being considered at the present time.

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

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

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

For Use by NERC Only

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

Version History

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	April 8, 2021 (Revised on November 16, 2021)		
SAR Requester			
Name:	Terry Volkmann (Revised by Project 2021-04 SAR Drafting Team)		
Organization:	Glencoe Light and Power NCR11444		
Telephone:	612-419-0672	Email:	terrylvolkmann@gmail.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The purpose of PRC-002-2[1] is to have adequate sequence of events recording (SER) and fault recording (FR) data available to facilitate analysis of Bulk Electric System[2] (BES) disturbances. Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data andimplicitly obligates these transformer or transmission line BES Element owners to either:			

[1] NERC Reliability Standard PRC-002-2 Disturbance Monitoring and Reporting Requirements (https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&Jurisdiction=United%20States) .

[2] See Glossary of Terms Used in NERC Reliability Standards (https://www.nerc.com/files/glossary_of_terms.pdf).

Requested information
1. W~~w~~ork with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on forcompliance, or 2. ~~the transformer or transmission line BES Element owner must i~~Install its own equipment that isduplicative to the identified BES Bus recording equipment. Below is Requirement R1 for reference: **R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-termPlanning] **1.1.** Identify BES buses for which sequence of events recording (SER) and fault recording(FR) data is required by using the methodology in PRC-002-2, Attachment 1. **1.2.** Notify other owners of BES Elements connected to those BES buses, if any, within90-calendar days of completion of Part 1.1, that those BES Elements **require** SER dataand/or FR data. **1.3.** Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement there-evaluated list of BES buses as per the Implementation Plan. Notifications for FR data are being sent to BES Element owners that extend well beyond the BES bus boundary described in PRC-002-2 Attachment 1 as “a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid.” Notifying BES Element owners beyond this boundary unnecessarily obligates the BES Element (i.e., transformer or transmission line) owner to Requirement R3, including joint owners. The PRC-002-2 implementation plan states “Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 and R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated the list.” This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan. Moving the three-year requirement from the PRC-002-2 implementation plan to the standard as a requirement language itself will provide clarity to Responsible Entities. Requirement R1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with R1.1. Depending on results of this re-evaluation, location at which SER/FR data is required could change due to minor change in three phase ~~SC~~short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on methodology in Attachment 1. The standard currently does not give any guidance on what is considered a substantial change in three phase ~~SC~~short circuit MVA. Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations would help with associated cost and compliance burden.

Requested information

If appropriate, ~~A~~add Planning Coordinator to the Western Interconnection in Section 4.1.3 as a Responsible Entity.

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

The goal of the proposed project is to:

- C~~c~~larify the necessary notifications in Requirement R1, Part 1.2 relative to the SER/FR data, and clearly identify the BES Element owners that need to have SER/FR data for transformers and transmission lines with the associated identified bus.
- Move requirement to be 100 percent compliant within three (3) years following notification of a re-evaluated list by the responsible entity from the implementation plan to the standard itself.
- Add a criterion that constitutes a substantial change in fault current levels which would require changing SER/FR data recording locations.
- If appropriate, ~~A~~add Planning Coordinator to the Western Interconnection in Section 4.1.3 as a possible Responsible Entity.

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

The scope should include:

- M~~m~~odifying Requirement R1, Part 1.2 to clarify notifications, which may include but is not limited to separating the notifications for SER data and/or FR data ~~regarding notification~~. Additionally, Requirement R3 should be modified so that it is abundantly clear to the applicable Transmission Owner and Generator Owner when their BES Element must have FR data for an applicable transformer or transmission line.
- C~~c~~larifying various terms such as "connected" and "directly connected" BES Elements and as necessary, ensure consistent usage of terms such as "BES bus" and "BES Element" in the standard.
- Codifying the three (3) year implementation period of newly identified buses in the re-evaluation performed per Requirement R1, Part 1.3 and R5.4 of the standard. The SDT should also clarify if this implementation period is three calendar years or three years from the notification from the responsible entity.
- Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations.
- If appropriate, ~~A~~adding Planning Coordinator to the Western Interconnection in Section 4.1.3 as a possible Responsible Entity.

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[3] 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 Transmission Owner (TO) applying the method in Attachment 1 who identifies a BES bus is in the ideal position to know which BES Elements (i.e., circuit breakers, transformer and transmission line) are

[3] 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
connected to a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. Additionally, the identified BES bus owner should know who owns the particular BES Element (i.e., circuit breaker) that needs SER and FR data to capture disturbances on generators, transformers, and transmission lines as identified in Requirement R3. Owners of BES Elements beyond the physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid should not be notified, unless their SER and FR data is needed to complete the identified BES bus SER and FR data. Requirement R1, Part 1.1 uses a method and BES bus definition[4] outlined in Attachment 1 to identify BES buses that requires SER data and/or FR data. Part 1.2 requires the notification of other BES Element owners connected to the identified BES bus under Requirement R1, Part 1.1. As currently written, a notification is required regardless of whether the identified BES bus owner has FR data for the intended BES Element (i.e., transformer or transmission line) or owns the BES Elements directly connected to the identified BES bus. Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. This will eliminate unnecessary notifications and obligations of the transformer and transmission line owners to compel other entities to have SER and FR data when there is no authority to do so. In these cases, the other BES Element owner(s) have to rely on SER and FR data from another entity that does not have the obligation under the standard. Additionally, clarifying the BES Element for which SER and FR data is required will reduce auditing needs resulting from notifying BES element owners who should not be responsible to have SER and FR data as well as reducing the cost burden of meeting the reliability need for SER and FR data. The standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. PRC-002-2 uses “connected” in Requirements R1.2 and R3, however, “directly connected” is used in Requirement R2. One interpretation of “connected” versus “directly connected” is shown in Figure 1, where all breakers are considered “directly connected” and other BES elements such as transmission lines, transformers and generators are “connected” to the bus. Figure 2 shows an example of a ring bus arrangement with possible classification of “connected” and “directly connected” BES elements.

[4] Attachment 1, Step 1: Determine a complete list of BES buses that it owns. For the purposes of this standard, a single **BES bus** includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

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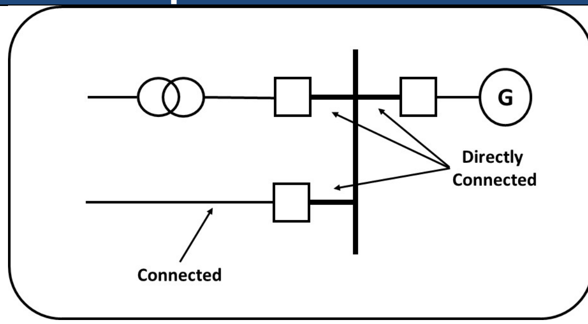


Figure 1

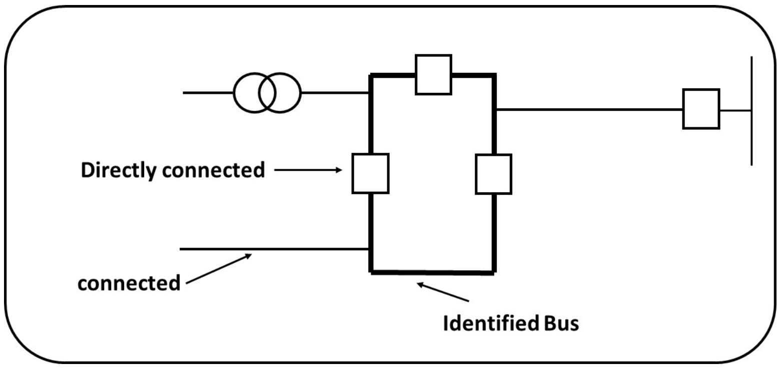
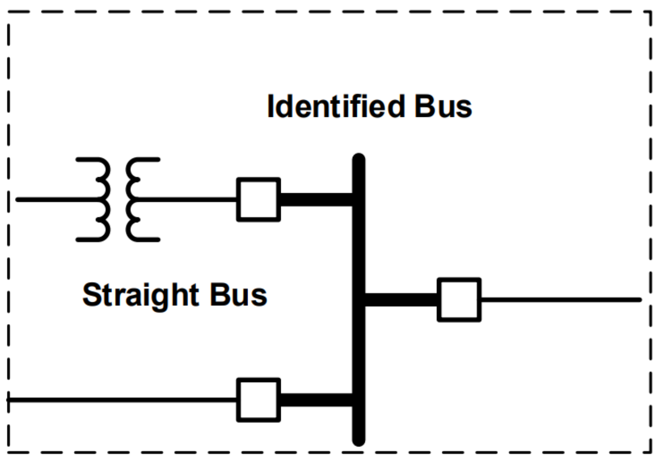


Figure 2



A straight bus configuration shown in Figure 3 ~~The above figure of a straight bus~~ is the simplest BES bus configuration sharing~~contained within~~ a common ground grid. Only the BES circuit breakers "1", "2" and "3" are "directly connected" to the identified BES bus.

Requested information

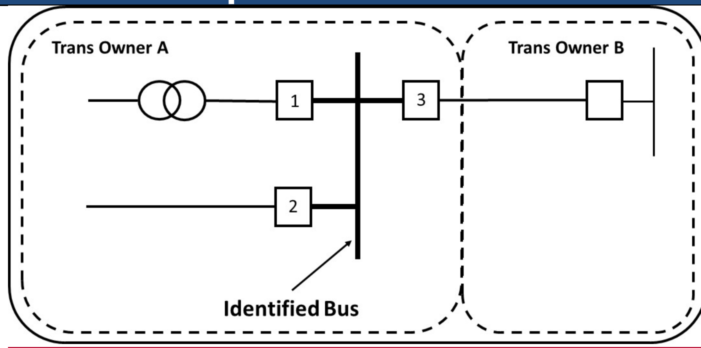


Figure 3

In this case, Transmission Owner A owns the BES bus as well as all breakers “directly connected” to it. In case where this BES bus is identified in Requirement R1, then Transmission Owner A is responsible for recording SER and FR data per Requirements R2 and R3 respectively. The Transmission Owner A should not be required to notify Transmission Owner B under Requirement R1.2 because Transmission Owner B does not own a BES element “directly connected” to the identified bus. However, per currently written Requirement R1.2, Transmission Owner A is required to notify Transmission Owner B. This has resulted in unnecessary notifications per Requirement R1.2 among various entities. The same is true for a ring bus configuration shown in Figure 4.

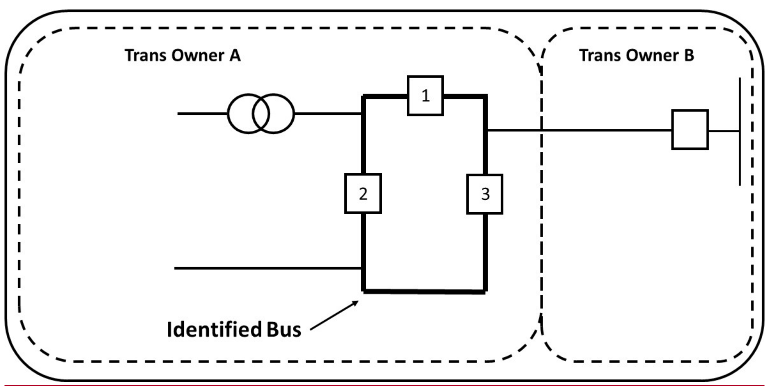


Figure 4

Figure 5 shows a variation of example in Figure 3, where BES breaker “3” is owned by Transmission Owner B. In this case, per Requirement R1.2, Transmission Owner A must notify Transmission Owner B that BES breaker “3” requires SER and FR data as breaker “3” is “directly connected” to the identified bus. In this case it is clear that~~concerning~~ SER data in Requirement R2 is required because the BES circuit breaker “3” is “directly connected~~.~~” to the identified bus. Although Requirement R3 does not mention “directly connected”, it is clear that Transmission Owner B is required to have FR data to determine specified electrical quantities for breaker “3”. From there how the compliance requirement is met is up to the involved entities.

Requested information

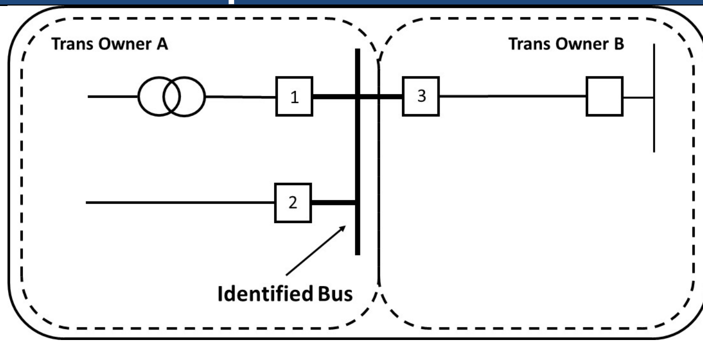


Figure 5

~~However, to achieve the need for FR data in Requirement R3, the identified BES bus owner notifies the transformer and transmission line owners under~~ Under the current Requirement R1, Part 1.2, the identified BES bus owner is required to notify all owners of ~~thus obligating them to have FR data where the circuit breaker is~~ "directly connected" breakers ~~and the logical BES Element to record~~ that SER and/or FR data is required.

Under the current Requirement R3, the notified Transmission Owner B is required to have FR data, either by obtaining FR data from Transmission Owner A~~GO and TO transformer or line owner will need to contact the circuit breaker owner in hope of obtaining FR data~~ or by installing their own equipment. The Transmission Owner B~~GO and TO~~ cannot compel the Transmission Owner A ~~circuit breaker owner~~ to provide~~have~~ FR data. Additionally, relying on another entity ~~that has no reliability responsibility~~ for complying with PRC-002-2 places Transmission Owner B~~the transformer or transmission line owner~~ at risk if the other entity fails to have the necessary and adequate FR data.

The intent of the standard in Requirement R3 is to have FR data associated with all applicable BES Elements at a single BES bus. This~~but that~~ includes physical buses with breakers "directly connected" at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus. Requirement R1, Part 1.2 should only require notification to the BES Element (i.e., circuit breaker) owner "directly connected" with the identified BES bus.

Under a ring bus configuration shown in Figure 6, elements (such as transmission lines, transformers etc.) that connect to the ring bus share BES circuit breakers for their protection system. The notifications per Requirement R1.2 by the identified bus owner are the same as with example in Figure 4. From there how the compliance requirement is met is up to the involved entities.

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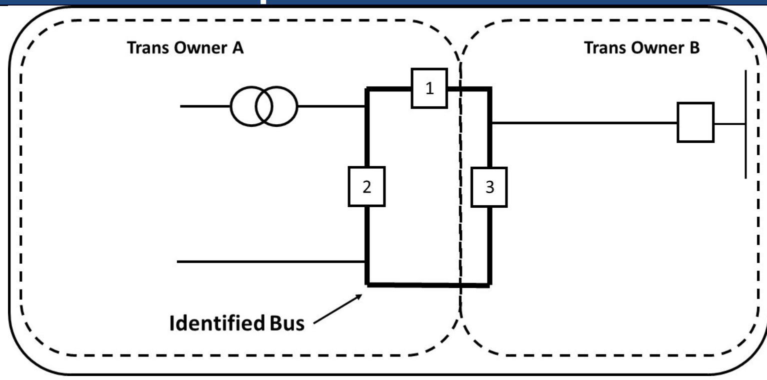

Figure 6

If one of the connecting elements is a generator as shown in Figure 7, Requirement R2 is clear about SER data obligation for the Generator Owner and notification from Transmission Owner to Generator Owner per Requirement R1.2 should be required. However, obligation for FR data per requirement R3 needs clarification as to if the Generator Owner is required or not to have FR data for breaker “3”. Requirement R3.2.1 exempts generator step-up transformers, implying that FR data would be available from equipment on the transmission system but this assumption may not be valid in all scenarios. The same clarification is also necessary for a configuration shown in Figure 8 where a generator is connected to the identified BES bus via a tie-line and the ownership of breaker “3” and the interconnecting tie-line belongs to the Generator Owner. From PRC-002-2 perspective, expectations for having FR data for breaker “3” is not different for scenarios presented in Figures 7 and 8.

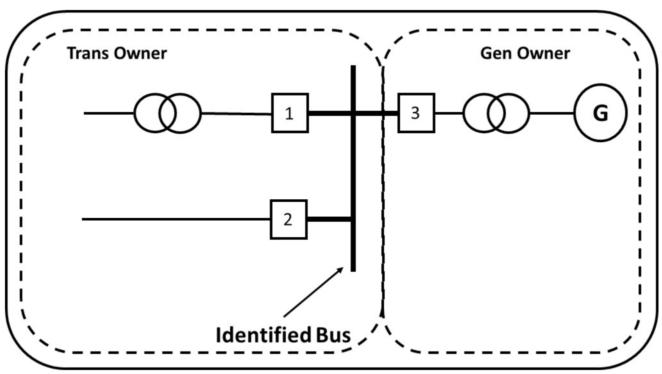

Figure 7

Requested information

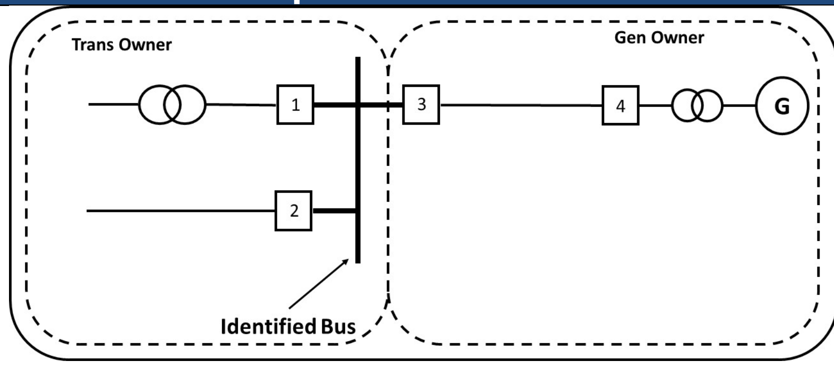

Figure 8

Identifying ~~Having~~ the appropriate BES Elements ~~identified~~ at the same voltage level within the same physical location sharing a common ground grid that requires SER and/or FR data will help facilitate obtaining data by only having to seek the data from those entities directly connected to the identified BES bus. However, the current standard could be interpreted that generation, transformer, and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus. As such, any modifications should consider alternative approaches that will achieve the intent of the standard while reducing associated cost and compliance burdens.

The PRC-002-2, R1.3 and R5.4 requires Responsible Entities to re-evaluate BES buses/BES Elements at least once every five calendar years and notify other owners…and implement the re-evaluated list of BES buses/BES Elements as per the Implementation Plan. The current PRC-002-2 implementation plan in turn requires that "Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated that list." This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan in order to understand the requirement to implement the re-evaluated list of BES buses/BES Elements on a three-year cycle. Moving the three-year requirement from the PRC-002-2 implementation plan to the standard as requirement language itself, as it is essentially a periodic requirement, will provide additional clarity to Responsible Entities as well as reduce the number of extraneous documents needed to comply with the standard.

Requirement R1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with R1.1, which refers to methodology presented in Attachment 1. Attachment 1, Step 7 specifies that if the list has one (1) or more but less than or equal to 11 buses the FR/SER data is required at the BES bus with the highest maximum available calculated three phase ~~SC~~short circuit MVA as determined in step 3. This is applicable to small Transmission Owners. During a re-evaluation, depending on minor system changes, it is likely that a bus with a highest maximum available three phase ~~SC~~short circuit MVA changes and would require installation of equipment to capture SER/FR data at this newly identified bus. This is justified if change in fault currents is large, however, if the change is minor then results in unnecessary burden on the Responsible Entity. Adding a criterion that constitutes

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a substantial change in fault current levels which would require changing SER and FR data recording locations would help with associated cost and compliance burden.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
For most part, the proposed modifications would eliminate unnecessary and administrative compliance burden for the Responsible Entities. If the revised standard requires disturbance monitoring equipment, approximate cost would be $50,000 to $100,000 per installation unless the existing equipment is set up for monitoring and storage. ~~None, the proposed modification above eliminates the unnecessary cost of being required to have FR data due to expanded notifications and the administrative burden to transformer and transmission line owners when these entities generally do not own the BES Elements that actually record the FR data.~~
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The standard already applies to TOs and GOs but depending on revision, additional generator interconnecting facilities might be required to provide FR data~~None~~.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owner and Generation Owner
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
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)?
A SAR was submitted by the NERC Inverter-Baser Resource Performance Task Force (IRPTF) to address potential gaps and improvements based on the work and findings of the IRPTF was authorized for posting by the NERC Standards Committee on January 20, 2021.
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.
Standard Implementation Guide or Practice Guide could provide the necessary clarity; however, these documents cannot change the strict language of the PRC-002-2 Reliability Standard. Nothing is being considered at the present time.

[5] 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
None	

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

Version History

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

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	June 10, 2020 (Revised on November 16, 2021, and April 5, 2023)		
SAR Requester			
Name:	Allen Shriver, Chair Jeffery Billo, Vice Chair Revised by Project 2021-04 SAR Drafting Team		
Organization:	Inverter-Based Resource Performance Task Force (IRPTF)		
Telephone:	Allen: 561-904-3234 Jeffery: 512-248-6334	Email:	Allen.Schriver@NextEraEnergy.com Jeff.Billo@ercot.com
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☐ Add, Modify, or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The “IRPTF Review of NERC Reliability Standards White Paper” was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed. The purpose of PRC-002-2 is to have adequate data available to facilitate the analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault			

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recording (FR) data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES). Requirements R1 and R5 are written with a focus on synchronous machine dominated systems with periodic reviews of monitoring equipment needs for the system. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. Inverter-based resources (IBRs) do not contribute many faults current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With the increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices. Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events. With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices and periodic assessments, the location requirements and associated periodic assessments need to be reconsidered. This is necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances. Instead of revising the latest PRC-002, the standard drafting team may consider creating a new standard to address needs identified in this SAR due to the primary audience being IBR Generator Owners and the fact that monitoring and respective technical requirements for IBRs may be significantly different from those for synchronous machines or transmission switching stations. The primary objective of this SAR is to not actually change existing requirements but instead add monitoring requirements for IBRs. If the new standard is developed to address the needs identified in this SAR, minimal changes to PRC-002 may still be necessary to avoid duplication of requirements. Review PRC-002 and make revisions as necessary to align with the new standard.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise PRC-002-2 or create a new standard to address gaps within the existing standard. The goal is to ensure adequate data is available and periodically assessed to facilitate the

Requested information
analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS buses for which SER and FR data is required provide adequate monitoring of BES Disturbances. This may include updates to supplemental information such as the previously provided "Median Method Excel Workbook". b. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS Elements for which DDR data is required provide adequate monitoring of BES disturbances. c. Consider other manners in which to add to, modify or clarify the existing requirements to ensure adequate monitoring of BES disturbances. This may include creating new requirements or a standard. d. Consider proposed IEEE P2800 monitoring requirements and NERC Odessa Disturbance Report recommendations.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide (1) a technical justification[1] that includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide the development of the Standard or definition):
Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with the highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data. However, BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute many faults current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring, though it is possible that monitoring in these areas is needed for disturbance analysis, as was the case in the Blue Cut Fire and Canyon 2 Fire events. Requirement R5 identifies BES locations based on size criteria for generating resources and other critical elements such as HVDC, IROLs, and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. Regarding generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or

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

Requested information
gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. However, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With the increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR devices to ensure adequate coverage for disturbance analysis while balancing cost impacts.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The SAR proposes to modify PRC-002-2 requirements or create a new standard. The cost impact is unknown, however, the cost of disturbance monitoring hardware is approximately $50,000 to $100,000 per installation if the existing onsite equipment is not already set up for monitoring and storage.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
IBRs contribute very little short circuit MVA and are typically smaller in aggregate nameplate rating when compared to legacy synchronous resources. The criteria for selecting disturbance monitoring locations should take this into account.
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, Reliability Coordinator, Generator Owner, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This issue was captured in the "IRPTF Review of NERC Reliability Standards White Paper" which was approved by the Operating Committee and the Planning Committee. Additionally, the IRPTF produced "BPS-Connected Inverter-Based Resource Performance"(see Chapter 6) and "Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources" reliability guidelines that touch on monitoring considerations for IBRs.
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)?
N/A
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The IRPTF did not identify any alternatives since there is a gap in PRC-002-2.

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

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

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

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

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

Version History

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

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	June 10, 2020 (Revised on November 16, 2021 and April 5, 2023)		
SAR Requester			
Name:	Allen Shriver, Chair Jeffery Billo, Vice Chair Revised by Project 2021-04 SAR Drafting Team		
Organization:	Inverter-Based Resource Performance Task Force (IRPTF)		
Telephone:	Allen: 561-904-3234 Jeffery: 512-248-6334	Email:	Allen.Schriver@NextEraEnergy.com Jeff.Billo@ercot.com
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The "IRPTF Review of NERC Reliability Standards White Paper" was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed. The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR)			

Requested information
data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES). Requirements R1 and R5 are written with a focus on synchronous machine dominated systems with periodic review of monitoring equipment needs for the system. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. Inverter-based resources (IBRs) do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices. Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events. With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices and periodic assessments, the location requirements and associated periodic assessments need to be reconsidered. This is necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances. In lieu of revising the latest PRC-002, the standard drafting team may consider creating a new standard to address needs identified in this SAR due to the primary audience being IBR Generator Owners and the fact that monitoring and respective technical requirements for IBRs may be significantly different from those for synchronous machines or transmission switching stations. The primary objective of this SAR is to not actually change existing requirements but instead add monitoring requirements for IBRs. If the new standard is developed to address needs identified in this SAR, minimal changes to PRC-002 may still be necessary to avoid duplication of requirements. Review PRC-002 and make revisions as necessary to align with the new standard.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise PRC-002-2 or create a new standard to address gaps within the existing standard. The goal is to ensure adequate data is available and periodically assessed to facilitate the

Requested information
analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS buses for which SER and FR data is required provides adequate monitoring of BES Disturbances. This may include updates to supplemental information such as the previously provided "Median Method Excel Workbook". b. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS Elements for which DDR data is required provides adequate monitoring of BES disturbances. c. Consider other manners in which to add to, modify or clarify the existing requirements to ensure adequate monitoring of BES disturbances. This may include creating new requirements or a standard. d. Consider proposed IEEE P2800 monitoring requirements and NERC Odessa Disturbance Report recommendations.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data. However, BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring, though it is possible that monitoring in these areas is needed for disturbance analysis, as was the case in the Blue Cut Fire and Canyon 2 Fire events. Requirement R5, identifies BES locations based on a size criteria for generating resources and other critical elements such as HVDC, IROLs and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. In regard to generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or

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

Requested information
gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. However, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR devices to ensure adequate coverage for disturbance analysis while balancing cost impacts.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The SAR proposes to modify PRC-002-2 requirements or create a new standard. The cost impact is unknown, however, the cost of disturbance monitoring hardware is approximately $50,000 to $100,000 per installation if the existing onsite equipment is not already set up for monitoring and storage.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
IBRs contribute very little short circuit MVA and are typically smaller in aggregate nameplate rating when compared to legacy synchronous resources. The criteria for selecting disturbance monitoring locations should take this into account.
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, Reliability Coordinator, Generator Owner, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This issue was captured in the “IRPTF Review of NERC Reliability Standards White Paper” which was approved by the Operating Committee and the Planning Committee. Additionally, the IRPTF produced “BPS-Connected Inverter-Based Resource Performance”(see Chapter 6) and “Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources” reliability guidelines touch on monitoring considerations for IBRs.
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)?
N/A
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The IRPTF did not identify any alternatives since there is a gap in PRC-002-2.

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

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

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

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

For Use by NERC Only

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

Version History

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

Standard Development Timeline

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

Description of Current Draft

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

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

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

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

Term(s):

N/A.

A. Introduction

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

B. Requirements and Measures

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

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

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

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

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

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

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

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

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

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

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

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

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

3.2.2. Transmission Lines.

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

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

4.1. A single record or multiple records that include:

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

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

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

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

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

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

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

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

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

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

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

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

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

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

5.2.1. One BES Element; and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

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

- Rate of change of frequency trigger set at:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) 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 CEA 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 CEA to retain specific evidence for a longer period of time as part of an investigation.

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

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

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

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

calendar years.

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

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

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

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

1.3. Compliance Monitoring and Enforcement Program:

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

1.4. Additional Compliance Information

None.

Violation Severity Levels

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

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

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

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

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

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

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

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

					than or equal to 12 months.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

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

G. References

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

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

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

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

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

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

Version History

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

Attachment 1

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

(Requirement R1)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

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

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

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

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

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

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

High Level Requirement Overview

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

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

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

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

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

Description of Current Draft

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

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

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

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

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-54
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Owner

   4.1.3. Generator Owner

   4.2. Facilities: BES Elements, excluding inverter-based portions of generating plants/Facilities meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition.[1]

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

B. Requirements and Measures

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

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-54, Attachment 1.

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

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

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-54, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

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

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

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

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

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

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

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

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

3.2.2. Transmission Lines.

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

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

4.1. A single record or multiple records that include:

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

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

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

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

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

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

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

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

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

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

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

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

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

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

5.2.1. One BES Element; and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

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

- Rate of change of frequency trigger set at:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) 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 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 CEA 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 CEA to retain specific evidence for a longer period of time as part of an investigation.

~~**1.2. Data**~~**Evidence** ~~**Retention:**~~

~~The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to~~

~~provide other evidence to show that it was compliant for the full time period since the last audit.~~

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

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

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

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

The Generator Owner shall retain evidence of Requirement R7, ~~Measure M7~~ for three calendar years.

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

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

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

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

1.3. Compliance Monitoring and Enforcement Program:

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

- Complaints

1.4. Additional Compliance Information

None.

Violation Severity Levels

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

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

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

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

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

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

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

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

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

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

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

G. References

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

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

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

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

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

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

Version History

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

Attachment 1

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

(Requirement R1)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

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

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

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

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

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

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

High Level Requirement Overview

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

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

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

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

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

Description of Current Draft

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

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

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

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

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
2. **Number:** PRC-028-1
3. **Purpose:** To have adequate data available from inverter-based resources (IBR) to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Owner that owns equipment as identified in section 4.2

   4.1.2. Generator Owner that owns equipment as identified in section 4.2

   4.2. Facilities: The following Elements associated with BES generating plants (inverter-based portion of generating plant/Facility meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition):

   4.2.1 Circuit breaker(s).

   4.2.2 Main power transformer(s)[1].

   4.2.3 Collector bus.

   4.2.4 Shunt static or dynamic reactive device(s).

   4.2.5 At least one IBR unit[2] connected to last 10% of each collector feeder length (i.e., furthest from the collector bus).

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

B. Requirements and Measures

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

1.1. Circuit breaker position (open/close) for circuit breakers associated with the Elements identified in section 4.2.

1.2. At least one IBR unit connected to last 10% of each collector feeder length. IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded.

1.2.1. All fault codes.

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

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

1.2.2. All fault alarms.

1.2.3. Change of operating mode.

1.2.4. High and low voltage ride-through.

1.2.5. High and low frequency ride-through.

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

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

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

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

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

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

2.1.3. Real and Reactive Power.

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

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

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

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

2.3. Dynamic reactive device

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

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

2.3.3. Real and Reactive Power output.

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

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

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

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

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

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

3.2. IBR unit level data

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

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

3.2.3. Trigger settings for at least the following:

3.2.3.1. AC Phase overvoltage and undervoltage.

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

3.2.3.3. Overfrequency and underfrequency.

3.3. Dynamic reactive device FR data

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

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

3.3.3. Trigger settings for at least the following:

3.3.3.1. Neutral (residual) overcurrent.

3.3.3.2. AC phase overvoltage and undervoltage.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) 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.

[3] American Standard Code for Information Exchange.

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 CEA 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 CEA to retain specific evidence for a longer period of time as part of an investigation.

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

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

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

1.3. Compliance Monitoring and Enforcement Program:

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

1.4. Additional Compliance Information

None.

Violation Severity Levels

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

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

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

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

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

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

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

G. References

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

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

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

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

NERC Reliability Standard PRC-002-5.

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

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

Version History

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

Attachment 1

Sequence of Events Recording (SER) Data Format

(Requirement R7, Part 7.3)

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

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

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

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

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

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

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

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

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

Implementation Plan

Project 2021-04 Modifications to PRC-002 - Phase II
Reliability Standards PRC-002-5 and PRC-028-1

Applicable Standard(s)

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

Requested Retirement(s)

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

Applicable Entities

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

General Considerations

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

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

Effective Date of PRC-002-5

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

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

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

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

Reliability Standard PRC-028-1

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

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

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

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

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

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

Compliance Date for PRC-028-1 Requirement R8

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

Retirement Date

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

Prior Implementation Plan

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

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

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Unofficial Comment Form

Project 2021-04 Modifications to PRC-002-5 – Phase II

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-04 Modifications to PRC-002 – Phase II** by **8 p.m. Eastern, Thursday, September 14, 2023.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 470-542-6882.

Background Information

This project will be completed in two phases. The first phase addressed the scope regarding notifications relative to the sequence of events recording (SER) and fault recording (FR) data, and to clearly identify the BES Element owners that need to have SER and FR data for transformers and transmission lines with the associated identified bus in the Glencoe Light and Power SAR.

The second phase will address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.

Questions

1. Do you agree with the modification in "Applicability, Section 4.2. Facilities" in PRC-002-5?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the need of creating a new Standard (PRC-028-1) to address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

   ☐ Yes
   ☐ No

   Comments:

5. Provide any additional comments for the standard drafting team to consider, if desired.

   Comments:

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Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-002-5)

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 PRC-002-5. 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.

VRF Justification for PRC-002-5, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R1

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R2

The VRF did not change from the previously FERC approved PRC-002-4Reliability Standard.

VSL Justification for PRC-002-5, Requirement R2

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R3

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R3

VSLs for PRC-002-5, Requirement R3			
Lower	Moderate	High	Severe
The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of

number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-002-5, Requirement R3	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justification for PRC-002-5, Requirement R4

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R4

VSLs for PRC-002-5, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.

VSL Justifications for PRC-002-5, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R4	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R5
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R6

VSLs for PRC-002-5, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R6	
Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R7

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R7

VSLs for PRC-002-5, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities,

total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-002-5, Requirement R7	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R8
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R8
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R9
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R9
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R10
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R10
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R11
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R11

VSLs for PRC-002-5, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-002-5, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-028-1)

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 PRC-028-1. 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-028-1

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.

VSL Justifications for PRC-028-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R1	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
	capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as

directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R4	
for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

VSL Justifications for PRC-028-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R6	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 failed to provide the requested data more than 60 calendar days

more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R7	
Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and failed to provide a Corrective Action Plan to the Regional Entity more than 120 calendar

than or equal to 100 calendar days after discovery of the failure.	than or equal to 110 calendar days after discovery of the failure.	than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R8	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Technical Rationale for Reliability Standard PRC-002-5

August 2023

PRC-002-5 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the Bulk Electric System (BES), the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for inverter-based resources (IBRs) to aid with event analysis, performance monitoring, and disturbance-based IBR generating facility model validation. The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the BES. Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. Introducing IBR monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for IBRs is created instead of revising the Reliability Standard PRC-002. To avoid any overlap between the Reliability Standards PRC-002 and PRC-028, BES Elements within inverter-based portions of generating plants/Facilities meeting the criteria set by Inclusion I2, part (b) or Inclusion I4 of the BES definition. Example in Figure 1 is provided to clarify applicability of Reliability Standards PRC-002 and PRC-028. The IBR generating facility in this example meets the criteria in inclusion I2 of the BES definition. The BES bus in substation Scott is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for BES Elements associated with the identified BES bus are per the Reliability Standard PRC-002 except for Elements associated with the IBR generating facility, i.e., circuit breaker 3. The SER, FR, and DDR data requirements for the IBR generating facility are specified in the Reliability Standard PRC-028.

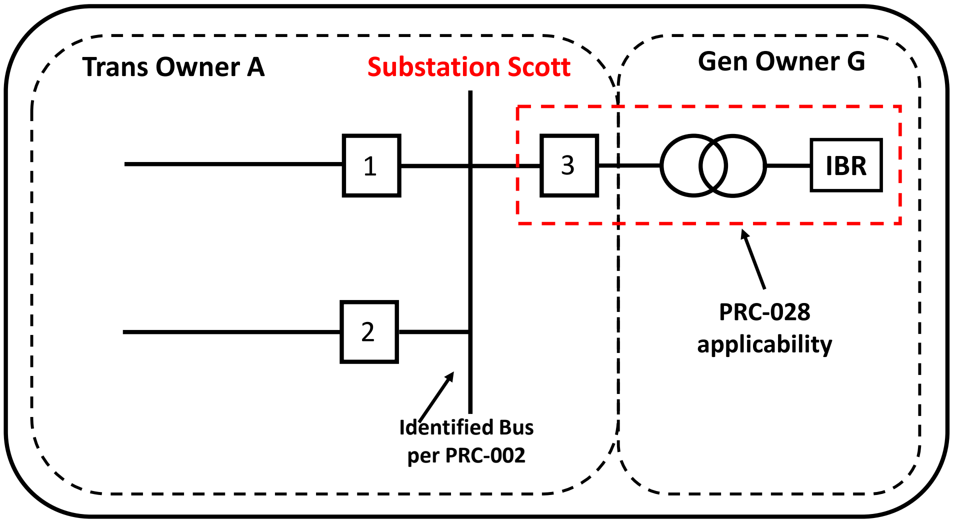

Figure 1: Example to Clarify Applicability of PRC-002 Versus PRC-028

Rationale for Requirement R1

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the Disturbance Monitoring Standard Drafting Team (DMSDT) data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-5, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three-phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

5. Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three-phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.

7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three-phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three-phase short circuit MVA of the newly identified BES bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B, and C are identified in Step 6. The maximum three-phase short circuit MVA of buses A, B, and C is 1600 MVA, 1500 MVA, and 1550 MVA respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three-phase short circuit MVA of buses A, B, and C is 1550 MVA, 1675 MVA, and 1600 MVA respectively. The bus B is the one with highest maximum three-phase short circuit MVA now. The three-phase short circuit MVA of bus B is within 15% of the three-phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three-phase short circuit MVA of buses A, B, and C is 1500 MVA, 1750 MVA, and 1650 MVA respectively. The three-phase short circuit MVA of bus B is greater than 15% of three-phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse

power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of “directly connected” BES Elements are notified. For the purposes of this standard, “directly connected” BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 2 and 3 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

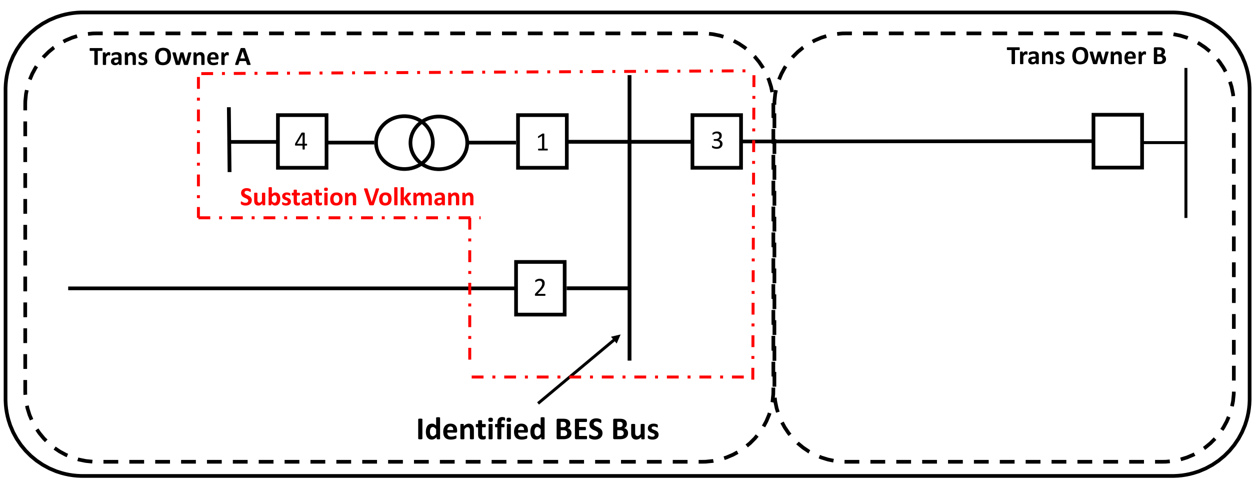

Figure 2: Straight Bus Configuration – Single Owner

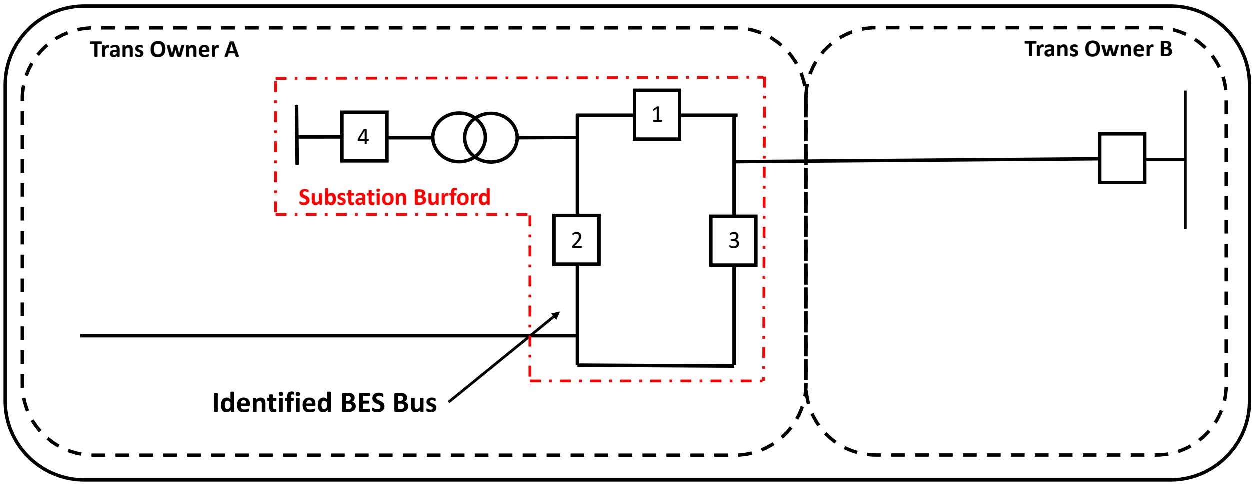

Figure 3: Ring Bus Configuration – Single Owner

Figures 4 and 5 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

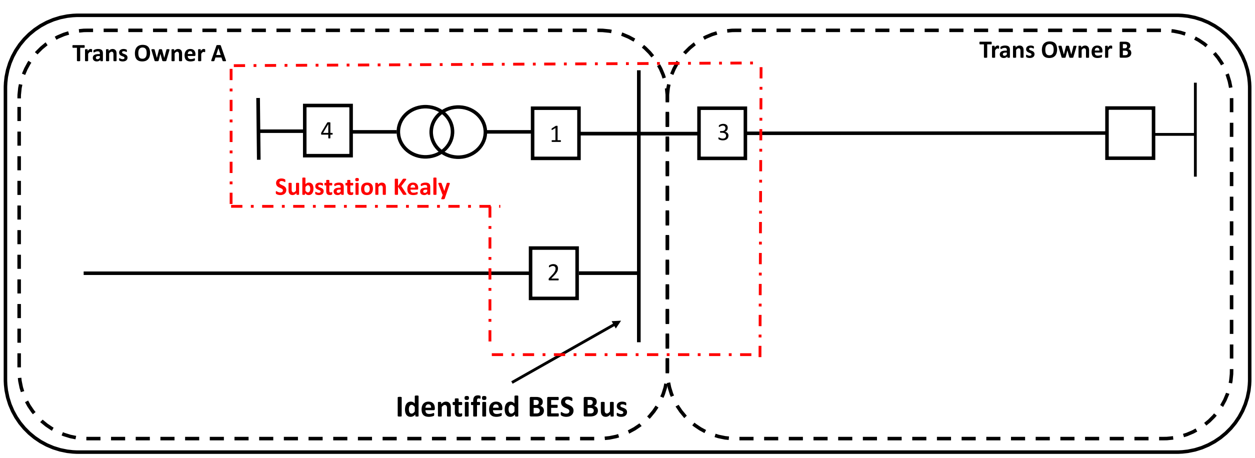

Figure 4: Straight Bus Configuration – Multiple Owners

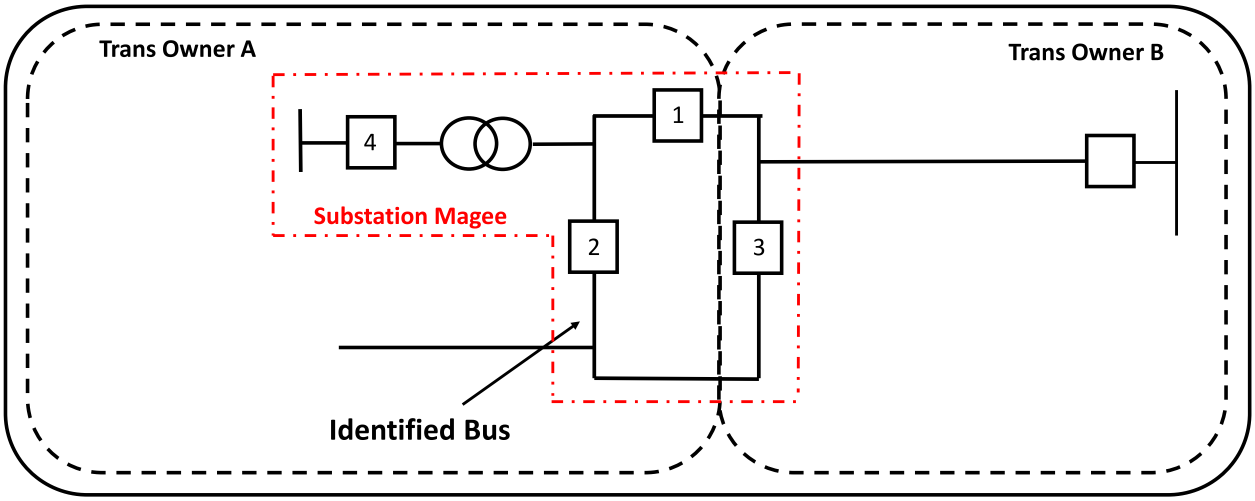

Figure 5: Ring Bus Configuration – Multiple Owners

For examples in Figures 4 and 5, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 6 shows an example with a generator interconnection. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

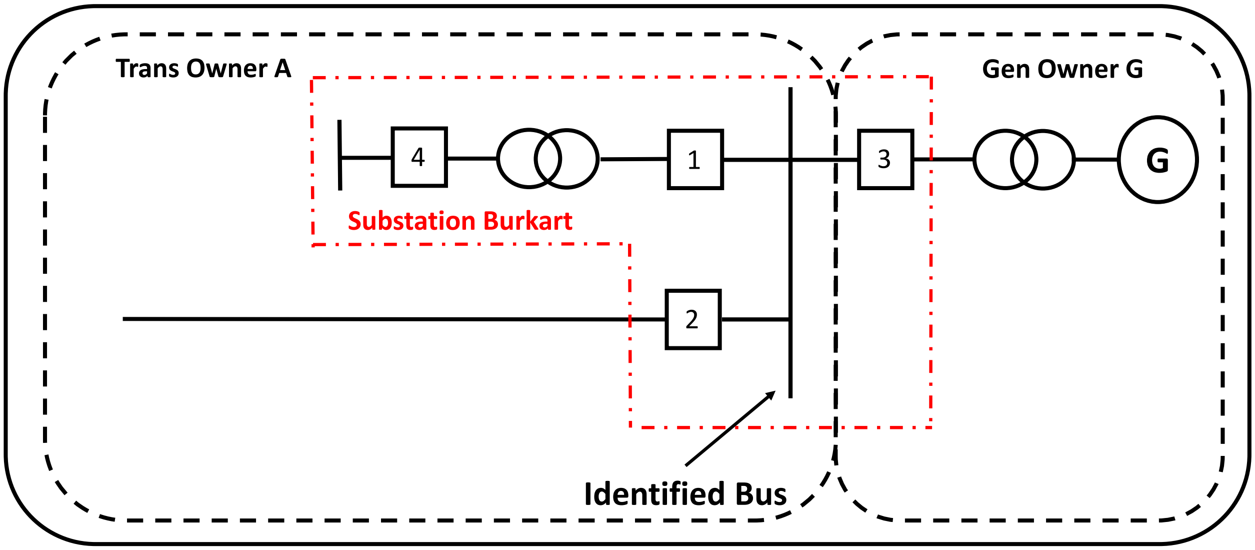

Figure 6: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 7, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

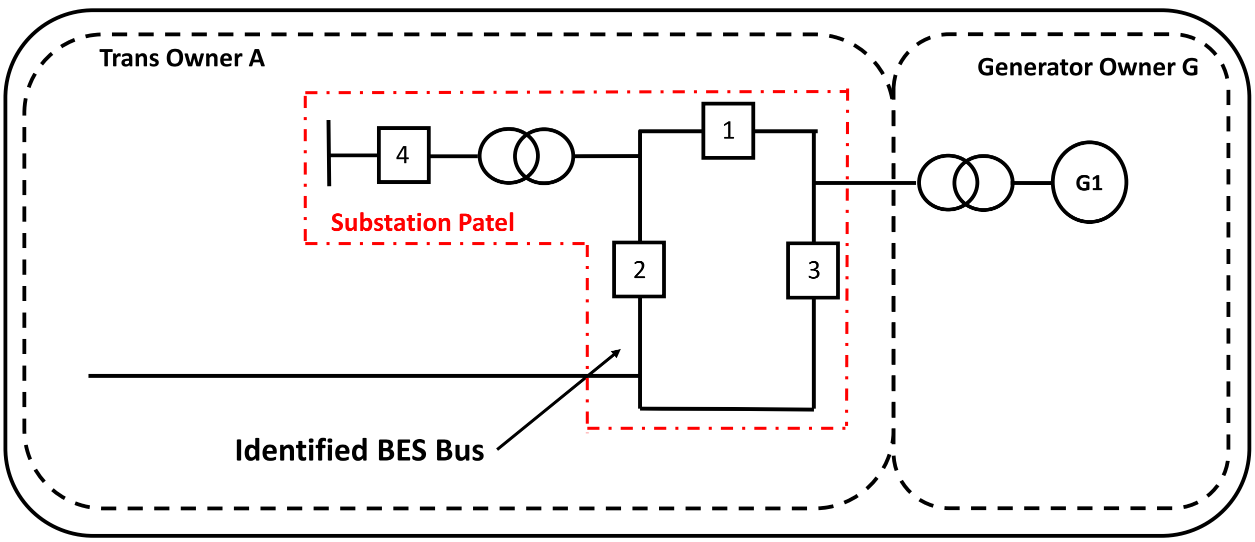

Figure 7: Generator Interconnection to Ring Bus

Figure 8 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical

bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

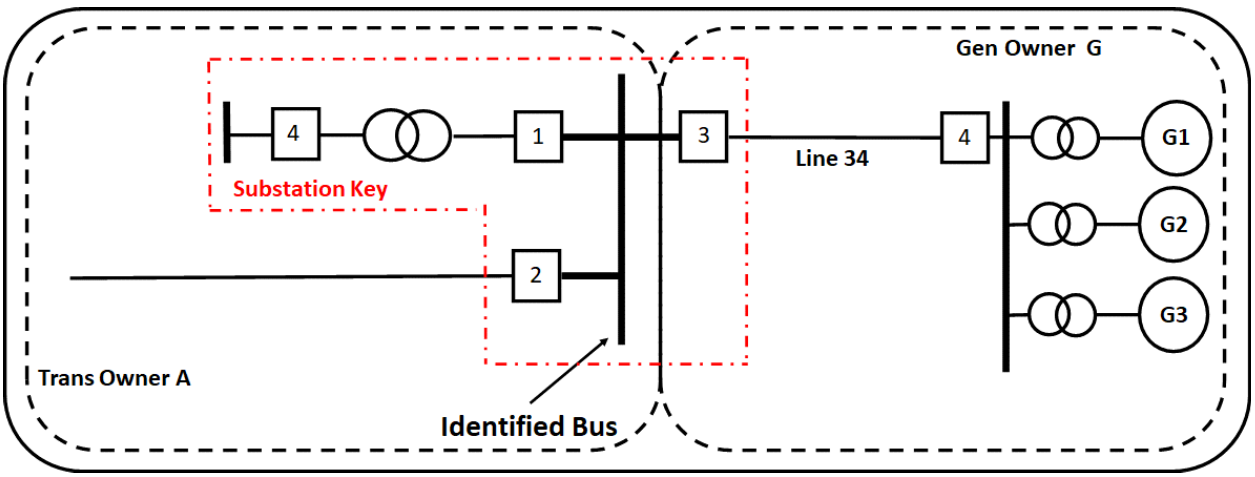

Figure 8: Generator Interconnection via Line 34

Figure 9 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3, and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

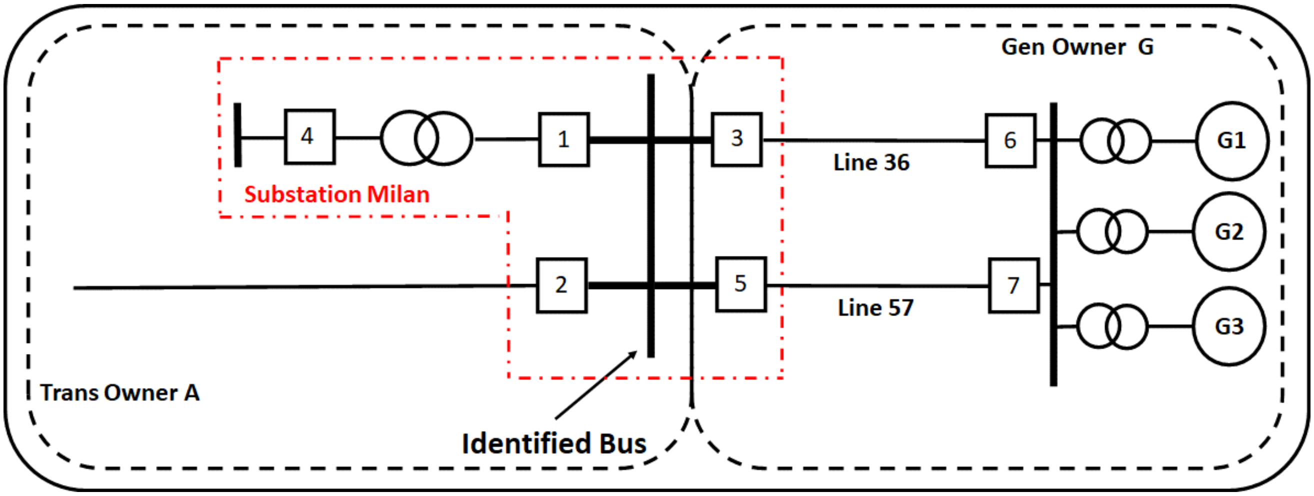

Figure 9: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification Transmission Owner B

Greetings,

In accordance with NERC Standard PRC-002-5, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Rationale for Requirement R2

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element directly connected to a BES bus. Change of state of circuit breaker position and time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position.

However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Examples in Figures 10, 11, and 12 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement R3

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads 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 are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements directly connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element directly connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities, it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

Examples in Figures 10, 11, and 12 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

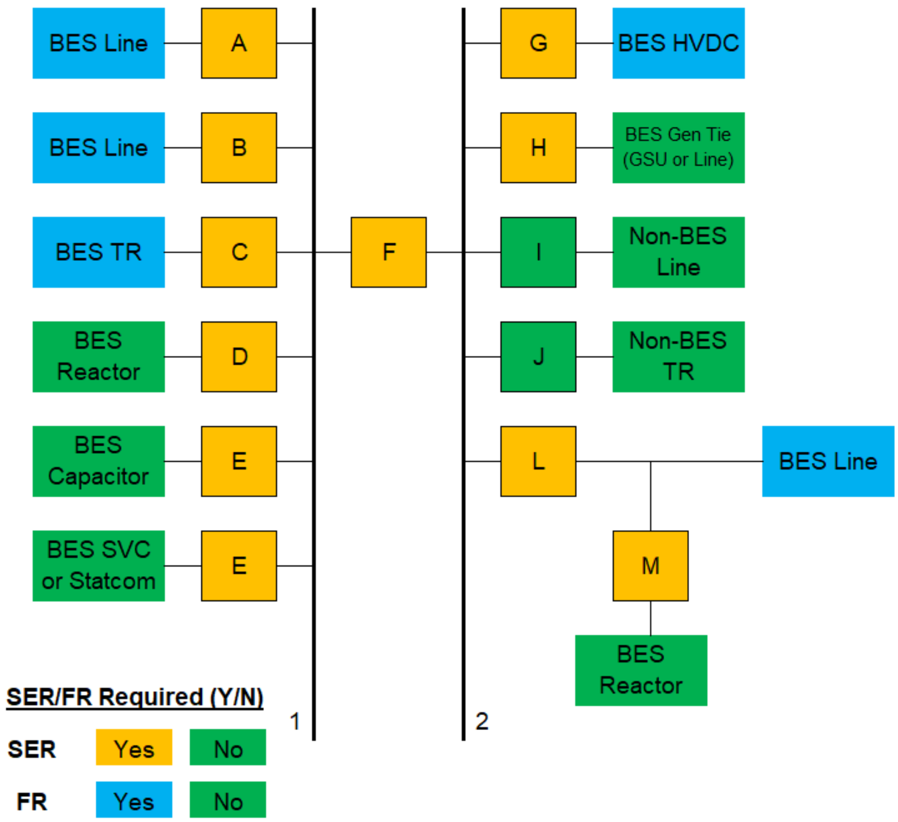

Figure 10: Straight BES Buses

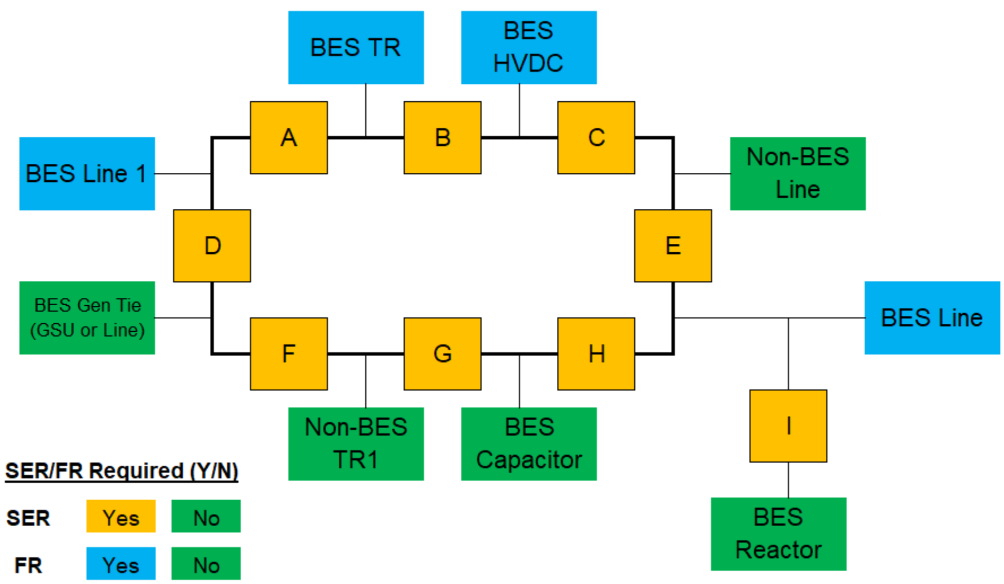

Figure 11: Ring BES Bus

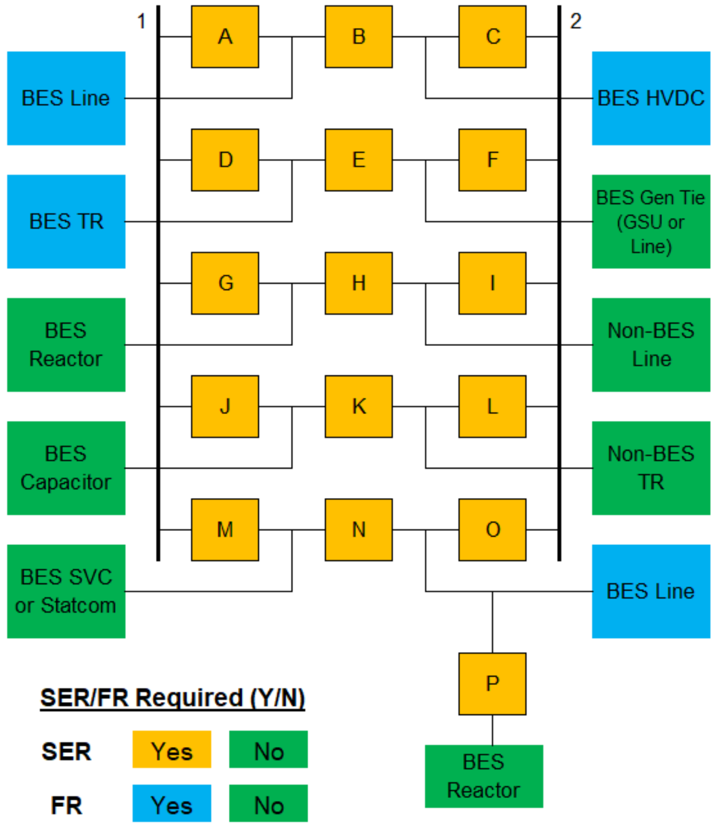

Figure 12: Breaker and Half BES Bus

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example, residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r}$, is calculated as a sum of vectors of three

phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings
Voltages are to be recorded or accurately determined at applicable BES buses

Rationale for Requirement R4
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30- contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Rationale for Requirement R5
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for

specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data, as per Requirement R5, is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element, as defined by the Reliability Coordinator, must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and

oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System-wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means, and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes.

However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather, the drafting team believes this determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR, such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Rationale for Requirement R6

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral

voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three-phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Rationale for Requirement R7

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at eitherthe high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the ‘what’ of DDR, not the ‘how’. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again, it must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement R8

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post- contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Rationale for Requirement R9

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.
DDR data contains the dynamic response of a power System to a Disturbance and is used for

analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Rationale for Requirement R10

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment.

Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement R11

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30 calendar days (or the granted extension time), subject to Part 11.2, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10 calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity, or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.2 specifies the maximum time frame of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.1 specifies that the minimum time period of 10 calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Rationale for Requirement R12

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90 calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System.

Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90 calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Technical Rationale for Reliability Standard PRC-028-1

August 2023

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

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for inverter-based resources (IBRs) to aid with event analysis, performance monitoring, and disturbance-based IBR generating facility model validation. These disturbance reports recommended to install disturbance monitoring equipment (DME) at wind and solar photovoltaic (PV) resources to ensure adequate data is available for event analysis, performance monitoring, and validating IBR generating facility models. The recommendation included plant-level high resolution oscillography data, plant SCADA data with a resolution of one second, sequence of events recording for all IBR units[1] that include all fault codes, and at least one IBR unit on each collector feeder configured to capture high resolution oscillography data within the IBR unit.

The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. The recent disturbance analyses of events involving IBRs (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have demonstrated that IBR's response to a normally cleared few cycle fault is undesirable and poses risk to system reliability. All these disturbance analyses have identified that IBRs involved did not have sufficient monitoring data to understand the plants' responses. The initiating event, e.g., a normally cleared transmission fault, was not a large-scale system disturbance; however, IBR plant's undesirable response due to a system fault resulted in a larger system disturbance. Adequate monitoring data is required to understand IBR plant's performance. Most of the IBRs involved in these disturbances did not have and were not required to have adequate disturbance monitoring data. The lack of disturbance monitoring data available from these facilities led to difficulty in adequately assessing the events. Introducing IBR monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for IBRs is created instead of revising the Reliability Standard PRC-002.

The Transmission Owners and Generator Owners, as applicable, will have the responsibility for ensuring that adequate data is available for applicable Elements at the applicable IBR generating facilities. This

[1] IBR unit includes the inverter, wind turbine generator etc.

standard requires that sequence of events recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data is available from the applicable IBR generating facilities.

Rationale for Applicability Section
Functional Entities
The two functional entities that are responsible for implementing disturbance monitoring equipment and collecting recording data are: Generator Owner and Transmission Owner. The standard is only applicable to Transmission Owner in case where Transmission Owner owns equipment within the IBR Plant.

Applicable Facilities
The following facilities from the BES definition are in the scope of this standard:

- Inverter-based portion of generating plant/Facility meeting the criterion set by Inclusion I2, part (b)
- Generating plant/Facility meeting the criteria set by Inclusion I4

The following Elements associated with BES generating plants noted above are in the scope of this standard:

- Circuit breaker(s)
- Main power transformer(s)
- Collector bus
- Shunt static or dynamic reactive device(s)
- At least one IBR unit connected to last 10% of each collector feeder length (i.e., furthest from the collector bus)

The following examples are provided to clarify applicability of the PRC-028 standard.

Example 1: Applicability of PRC-028
Figure 1 shows a typical single line diagram of an IBR generating facility. The IBR generating facility is connected to the transmission system via a short tie-line. The length of collector feeder #1, #2, and #3 is 3000 ft, 2500 ft, and 2800 ft respectively. IBR units #6 and #7 are connected to collector feeder #1 at 2800 ft and 3000 ft distance from the collector bus respectively. In other words, these IBR units are connected to last 10% of the collector feeder #1. This IBR generating facility is equipped with a dynamic reactive device (e.g., synchronous condenser, static VAR compensator etc.) connected to the collector bus.

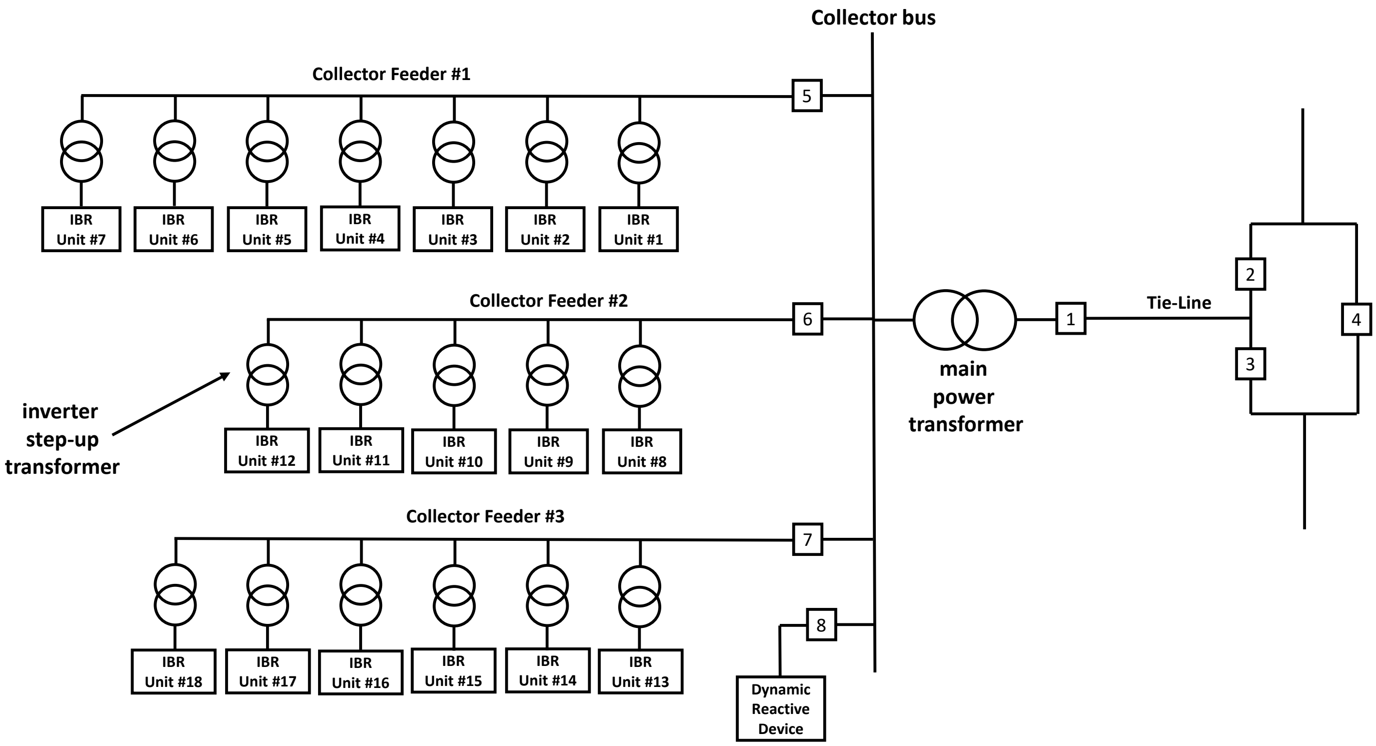

Figure 1: Typical IBR Generating Facility Single Line Diagram

SER Data: The SER data is required for circuit breakers 1, 5, 6, 7, and 8. Circuit breaker 1 is associated with the main power transformer. Circuit breakers 5, 6, 7, and 8 are associated with the collector bus. The SER data for either IBR unit #6 or #7 is required as both are connected to last 10% of the collector feeder #1 length. Similarly, at least one IBR unit connected to last 10% of collector feeder #2 and #3 is also required to have SER data.

FR Data: The FR data is required from high side terminals of the main power transformer. In this example, the IBR plant consists of only one main power transformer. If the IBR plant consists of more than one main power transformer, then FR data for each main power transformer is required. The FR data for either IBR unit #6 or #7 is required as both are connected to last 10% of the collector feeder #1 length. Similarly, at least one IBR unit connected to last 10% of collector feeder #2 and #3 is also required to have FR data. As the IBR plant is equipped with the dynamic reactive device, the FR data for it also required.

DDR Data: The DDR data is required from high side terminals of the main power transformer. If the IBR plant consists of more than one main power transformer, then DDR data for each main power transformer is required. The DDR data from individual IBR units is not required.

Example 2: Applicability of PRC-002 versus PRC-028

Figure 2 shows an example of IBR interconnection to the transmission system via Line 34. The BES bus in substation Wu is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for the identified BES bus are per the requirements in the Reliability

Standard PRC-002. The IBR generating facility in this example meets the criteria set by inclusion I2 of the BES definition. Hence, the Reliability Standard PRC-028 is applicable to the IBR generating facility.

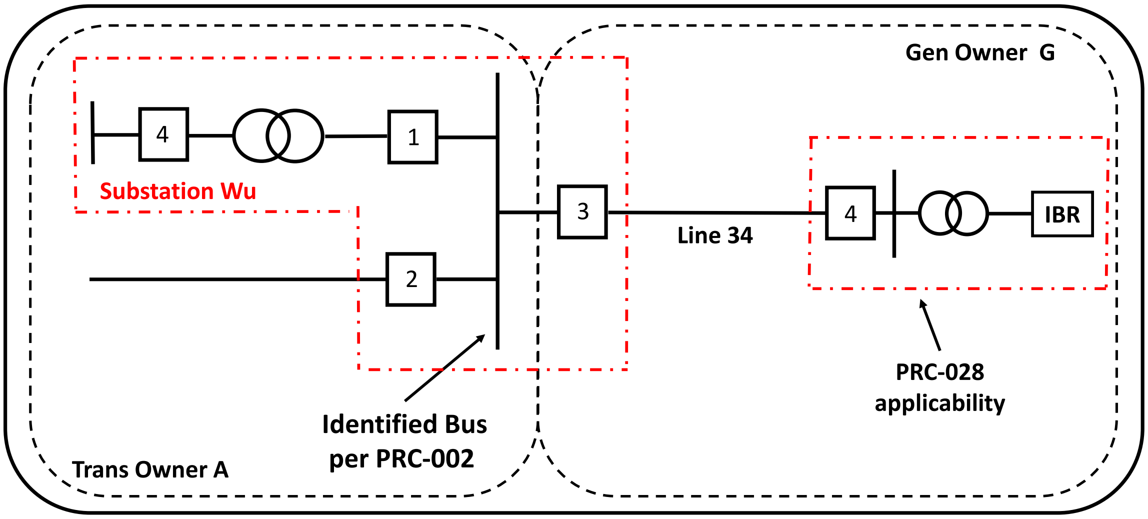

Figure 2: IBR Interconnection – Applicability of PRC-002 versus PRC-028

<u>Example 3: Transmission Owner owned Equipment within the IBR generating facility</u>

Figure 3 shows an example of an IBR interconnection where Transmission Owner A owns circuit breaker 3 associated with an IBR generating facility. In this case, Transmission Owner A is responsible for SER data for circuit breaker 3. It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an IBR generating facility. However, in cases where this is true, Transmission Owner is responsible for SER, FR, and DDR data, as applicable, required by the Reliability Standard PRC-028.

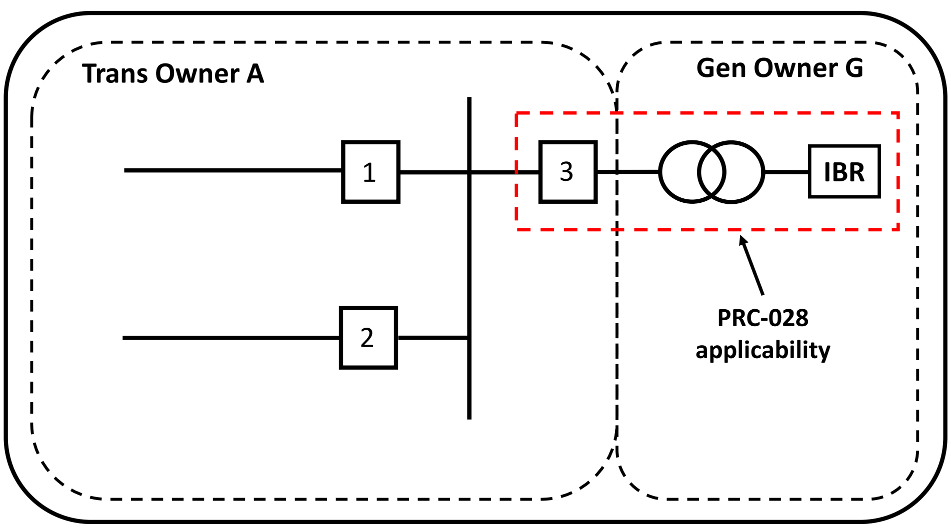

Figure 3: Transmission Owner owned Equipment within an IBR Plant

Example 4: Hybrid Plant (synchronous machine + IBR)

Figure 4 shows an example of a hybrid plant, i.e., synchronous machine + IBR, interconnecting to the transmission system via Line 34. The aggregate nameplate rating of this hybrid generating facility is greater than 75 MVA and meets the criteria set by inclusion I2, part (b) of the BES definition. The SER, FR, and DDR data for inverter-based portion of this hybrid generating facility is required.

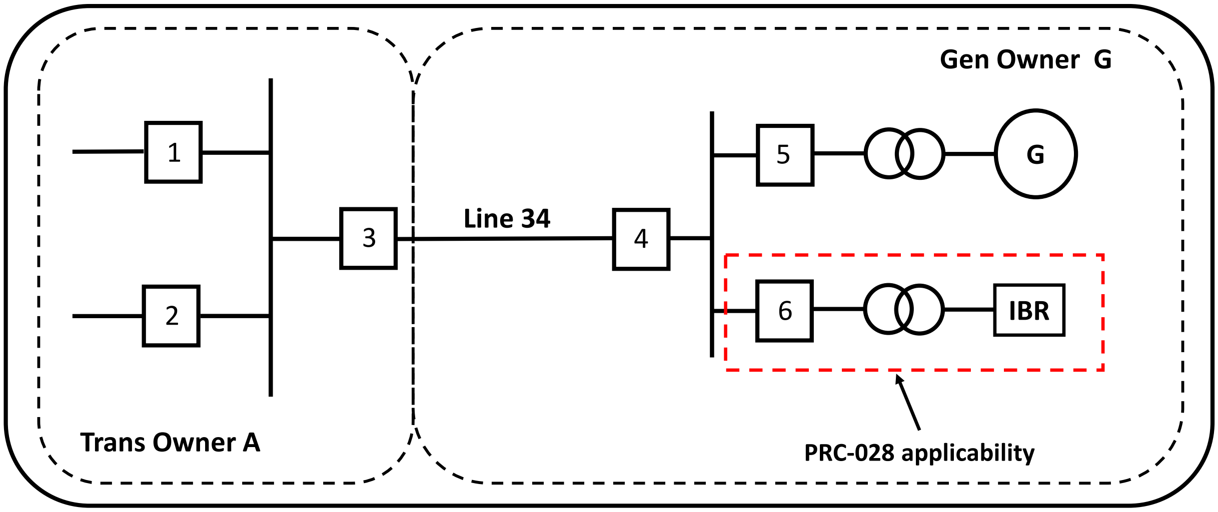

Figure 4: Hybrid Generating Facility

Rationale for Requirement R1

The standard requires to capture SER data from circuit breakers and IBR units within the IBR generating facility. At least one IBR unit connected to last 10% of each collector feeder length must have the data specified in R1, Part 1.2.1 through 1.2.6

Change of state of circuit breaker position and IBR unit data, time stamped according to Requirement R7 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of IBR generating facility's response during a power System disturbance. Analyses of system disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations helps determine the interruption of flows during the disturbances. Recording of at least one IBR unit connected to last 10% of each collector feeder length helps analysis of IBR unit performance during BES disturbances that do not operate the interconnecting circuit breaker. One IBR unit in the last 10% of the collector feeder length is specified because it may be the most challenging location for IBR units to continue to ride-through during BES disturbance.

Rationale for Requirement R2

The intent is to capture sufficient FR data for Elements at each IBR generating facility to analyze the overall response of the IBR generating facility to a system disturbance. Analyses of disturbances involving widespread reduction of power output from IBRs in recent years has shown that expansion of monitoring at IBR sites is necessary. The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured).

The plant level FR measurements, i.e., measured on high-side terminals of the main power transformer, specified in Requirement R2, Part 2.1 provide data at the IBR generating facility interconnection to the bulk power system. To cover all possible fault types, phase-to-neutral voltage recording for each phase is required to be determinable. Each phase current and residual current are required to distinguish between phase faults and ground faults. This data also facilitates determination of the fault location and cause of relay operation. The measurements of active and reactive power provide data on the overall generating facility's response to the system disturbance.

Analyses of system disturbances involving widespread reduction of real power output from IBRs in recent years have shown that all individual IBR units within the IBR generating facility do not react to the disturbance identically because of their wide geographic distribution. The choice of at least one IBR unit connected to the last 10% of each collector feeder length in Requirement R2, Part 2.2 requires monitoring on a selection from some of the most geographically remote IBR units at each site, ensuring that FR data is available to analyze individual IBR unit response. It may be challenging to record/determine specified electrical quantities from IBR unit terminals for existing installations. As such, the standard allows for recording/determining specified electrical quantities on high-side of IBR unit transformer.

In some cases, the dynamic reactive device is used within the IBR generating facility and often connected to medium voltage collector bus. Regardless of where dynamic reactive device is connected, the output of it during system disturbances is important to understand overall performance of the plant during a disturbance. The measured or determined electrical quantities for dynamic reactive device are same as those specified to be measured/determined from high-side of main power transformer.

Recording of Electrical Quantities

For effective fault analysis, it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation. FR also shows generator output response to a system disturbance.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120 degrees, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current Ir, is calculated as a sum of vectors of three phase currents:

$$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Voltage Recordings
Voltages are to be recorded or accurately determined at applicable Elements as outlined in Requirement R2.

Rationale for Requirement R3
Time stamped pre- and post-trigger FR data aid in the analysis of power system operations and determination if operations were as intended.

The "Odessa Disturbance" report from September 2021 recommended high resolution oscillography data at the point of interconnection and on individual IBR units. The minimum recording rate of 128 samples per cycle is specified recognizing state-of-the-art for DME including storage any storage capability limitations and provides sufficient data to recreate accurate response of the IBR generating facility to system disturbances. This higher sampling rate is particularly important for capturing transient events at the individual IBR units.

Pre- and post-trigger fault data along with the SER data, all time stamped to a common clock, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Additionally, IBR units employ fast acting control systems (with built in protection functions) dictating IBR generating facility's response to system disturbance. The FR data from IBR units time stamped to a common clock is necessary to analyze IBR unit and generating facilities response to system disturbances. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles. To capture the full response of IBR generating facility spread over a large geographic area, a two-second total minimum record length synchronized to a common clock is necessary for FR data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data but are not capable of providing fault data in a single record with 120 contiguous cycles total.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R3, Part 3.1.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R3, sub-Part 3.1.3.2 specifies a phase overvoltage or undervoltage trigger during voltage ride-through events. For IBR unit FR data triggers, Requirement R3, Part 3.2.3.1 specifies a phase overvoltage and undervoltage. Requirement R3, Part 3.2.3.2 specifies a trigger for DC overvoltage, DC overcurrent, and DC reverse overcurrent to monitor for abnormal DC quantities at the IBR unit resulting from system disturbances. Requirement R3, sub-Part 3.2.3.3 specifies a trigger for overfrequency and underfrequency to record response during frequency ride-through events.

The triggers specified in Requirement R3, Part 3.3 for dynamic reactive device FR data are similar to ones specified in Requirement R3, Part 3.1 for plant level FR data measured or determined on high-side of the main power transformer.

Rationale for Requirement R4
Large scale system disturbances generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps

identify the causes and IBR generating facility's response to large scale system disturbances. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event. The state-of-the-art DDR equipment is capable of continuous recording.

DDR data contains the dynamic response of the IBR generating facility to a system disturbance and is used for analyzing complex power system events. This recording is typically used to capture short-term and long-term disturbances. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

DDR is used to measure transient response to system disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage and current from the same phase or positive sequence for each applicable main power transformer for analysis. It is also sufficient to provide a single frequency for any of the provided voltages since all main power transformers within a IBR generating facility are at the same frequency. Recording of all three phases of voltage/current is not required, although this may be used to compute and record the positive sequence value(s). The electrical quantities for Real Power and Reactive Power on a three-phase basis can be measured/recorded or determined (calculated, derived, etc.).

The data requirements for PRC-028-1 are based on a system configuration assuming all normally closed circuit breakers on a BES bus are closed.

A crucial part of disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary to have DDR on high-side of the main power transformer(s) measuring the specified electrical quantities to adequately capture IBR generating facility's response.

The Requirement R4, Part 4.1 requires either one phase-to-neutral or positive sequence voltage. However, the phase-to-phase voltage recording is acceptable. Since the BES operates under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Rationale for Requirement R5

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltages and frequency. The input sampling rate specified is same as one specified in the Reliability Standard PRC-002.

An output recording rate of electrical quantities of at least 60 times per second refers to the recording rate of the device. Recorded measurements of at least 60 times per second provide adequate recording speed to monitor the IBR generating facility's response during power system disturbances. Since control system associated with IBRs is fast acting, higher frequency recording is necessary to accurately reconstruct events. An output recording rate of 60 times per second provides this higher frequency recording while not greatly increasing data storage requirements.

Rationale for Requirement R6

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 100 microsecond accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 100 microsecond accuracy will suffice with respect to providing time synchronized data. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. Note that the recently published IEEE Std 2800 requires the DME recording plant level data be synchronized to the clock with accuracy of ± 1 microsecond accuracy; however, the accuracy requirement is set to ± 100 microsecond to strike a balance between need of accuracy and practical limitations of equipment necessary to achieve the stated accuracy.

The IBRs, which are not affected by inertial time constants, make changes in power production very rapidly. To understand and analyze control decisions during system disturbances and the reasons behind them over dozens of plants with possibly 100’s of IBR units requires a high level of accurate time synchronization. Following provide some examples of IBR’s fast response:

- Typical 90% response to a three-phase fault is <40 ms.
- Central power plant controllers issue updated commands in as little as 40 ms upon detection of change in system conditions.
- Standard closed loop voltage control response can be <200 ms.
- Instantaneous Inverter protective trip decisions such as AC or DC overvoltage or reverse DC current can be made in less than 10 ms.

Rationale for Requirement R7

Requirement R7, Part 7.1 specifies a minimum time period of 30 calendar days inclusive of the day the data was recorded for which the data to be retrievable. Data hold requests are usually initiated the same or next day following a major event, however, it takes a longer time to determine which data from which generating facility needs to be retrieved for event analysis. A 30 calendar day time period provides enough time for communication between various Entities regarding the event and need for data retrieval from DME at various generating facilities. The requestor of data has to be aware of 30 calendar day retrievability limit to ensure timely data hold requests. Requiring data retention for a longer period of time is expensive and unnecessary.

With the state-of-the-art equipment, having the data retrievable for the 30 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 30 days. To clarify the 30 calendar day time frame, let's assume that event occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 31, that is outside the 30 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER, FR and DDR data for generating facilities as per the applicability. To facilitate the analysis of system disturbances, it is important that the data is provided to the requestor within a reasonable time. Providing the data within 30 calendar days (or the granted extension time), subject to Requirement R7, Part 7.2, allows for reasonable time to collect the data and perform any necessary computations or formatting. An entity may request an extension of the 30 calendar days submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Disturbance analysis includes reviewing data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis. The formatting and naming convention requirements for SER, FR, and DDR are consistent with same requirements in the Reliability Standard PRC-002.

SER data: Requirement R7, Part 7.3 specifies a simple ASCII Comma Separated Value (CSV) format according to Attachment 1. It is necessary to establish a standard format as it allows data submitted by one entity or facility to be incorporated with same data provided by other entities or facilities to develop a detailed sequence of events timeline of a power system disturbance.

FR and DDR data: Requirement R7, Part 7.4 specifies the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the FR and DDR data. The IEEE C37.111 is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources is typically incorporated to provide a detailed analysis of a power system disturbance. The 2013 revision of the IEEE C37.111 includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R7, Part 7.5 specifies the IEEE C37.232 Standard for Common Format for Naming Time Sequence Data Files (COMNAME) format for naming the SER, FR and DDR data files. The lack of a common naming practice seriously hinders the event analysis and investigation process.

Rationale for Requirement R8

The standard requires that Entity restore the recording capability for SER, FR, or DDR data within 90 calendar days of the discovery of a failure. The 90 calendar day time period permitted in this requirement strikes a balance between reasonable time needed to restore capability while ensuring that recording capability is not out of service for an extended duration. If the recording capability cannot be restored within 90 calendar days due to limitations such as budget cycle, service crews, vendors, needed outages, etc., the entity is required to submit a Corrective Action Plan for restoring the recording capability to the Regional Entity and implement it. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored Element does not constitute a failure of the disturbance monitoring capability.

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Open through September 14, 2023
Ballot Pools Forming through August 30, 2023

Now Available

A 45-day formal comment period for **Project 2021-04 Modifications to PRC-002- Phase II** is open through **8 p.m. Eastern, Thursday, September 14, 2023** for the following standards and implementation plan:

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

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact **ballotadmin@nerc.net** to assist with the removal of any duplicate registrations.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Wednesday, August 30, 2023.** 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 the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 5 - 14, 2023**.

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 2021-04 Modifications to PRC-002 observer list” 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:	2021-04 Modifications to PRC-002 – Phase II | Draft 1
Comment Period Start Date:	8/1/2023
Comment Period End Date:	9/14/2023
Associated Ballots:	2021-04 Modifications to PRC-002 – Phase II Implementation Plan IN 1 OT 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 | Non-Binding Poll IN 1 NB 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 IN 1 ST 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll IN 1 NB 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 IN 1 ST

There were 71 sets of responses, including comments from approximately 182 different people from approximately 121 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the modification in “Applicability, Section 4.2. Facilities” in PRC-002-5?

2. Do you agree with the need of creating a new Standard (PRC-028-1) to address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002?

3. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

4. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

5. 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	MRO,SPP RE,WECC	SRC 2023	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
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC

					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	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
					Scott Brame	North Carolina Electric Membership Corporation	1,3,4,5	SERC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Andy Fuhrman	Minnkota Power Cooperative, Inc.	1	MRO
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Andrew Anderson	Wolverine Power Supply Cooperative, Inc.	1	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO

					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO

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
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
					Frank Lee	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
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC

					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	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
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	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
					Joshua London	Eversource Energy	1	NPCC
Stephen Whaite	Stephen Whaite			ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC

					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	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 with the modification in “Applicability, Section 4.2. Facilities” in PRC-002-5?

Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Do not agree with modification. Modification implies that inverter-based resources are to be included in the BES definition Inclusion I2. This interpretation doesn’t conform with the current version of the BES definition.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
At some utilities we record wicket gate opening % by recording the 4-2 mA gate position in series with plant instrumentation.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Please clarify that the requirements for reporting only pertain to entities covered by the NERC standard. This can be accomplished by deleting footnote 1 and replacing the phrase “IBR generation loss” with “GO-IBR”.	
Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Talen supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Do not agree with modification. Modification implies that inverter-based resources are to be included in the BES definition Inclusion I2. This interpretation doesn't conform with the current version of the BES definition.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's comments which state: EEI does not agree with the modifications to the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in BES Definition, Inclusion I2. This interpretation does not conform to the approved version of the Bulk Electric System Reference Document, Version 3, dated August 2018. If NERC believes that this interpretation is no longer appropriate, or otherwise invalid, they should work with the industry to modify the BES definition and associated support documents. EEI further notes that this project was not approved to Add, Modify or Retire a Glossary Term.	

Likes 0	
Dislikes 0	

Response

Wendy Kalidass - U.S. Bureau of Reclamation - 5

Answer	No
Document Name	

Comment

Reclamation recommends that section 4.2 be removed as justification for limiting the inclusions from the BES Definition in the glossary of terms is not provided, limiting the scope of Disturbance Reporting.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with NAGF comments.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with NAGF comments.

Likes 0	
Dislikes 0	

Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	

Comment	
AZPS supports the following comments submitted by EEI on behalf of their members: EEI does not agree with the modifications to the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in BES Definition, Inclusion I2. This interpretation does not conform to the approved version of the Bulk Electric System Reference Document, Version 3, dated August 2018. If the interpretation is no longer appropriate, or otherwise invalid, the BES definition and associated support documents should be revised. EEI further notes that this project was not approved to Add, Modify or Retire a Glossary Term.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	
Comment	
SMUD and BANC support the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	
Comment	
PG&E supports the input provided by the NAGF related to cost and EEI related to the implied inclusion of Inverter-Based Resources (IBR) as part of the BES Definition.	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
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	No
Document Name	

Comment
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #1.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment
EEI does not agree with the modifications to the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in BES Definition, Inclusion I2. This interpretation does not conform to the approved version of the Bulk Electric System Reference Document, Version 3, dated August 2018. If the interpretation is no longer appropriate, or otherwise invalid, the BES definition and associated support documents should be revised. EEI further notes that this project was not approved to Add, Modify or Retire a Glossary Term.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment
The BES Reference Document, Version 3, August 2018, verbiage and clarifying illustrations indicate that I4 was created for IBRs, and that IBRs are included within scope only by I4 and not I2. Suggest either removing references to I2 in the proposed Applicability Section 4.2, or stating without specific inclusions, e.g., "... excluding inverter-based portions of generating plants/Facilities included in the BES by meeting the BES definition." Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	
The SRC agrees with the modification in Section 4.2 of the Applicability section in PRC-002-5; however, consistent with the recommended modification to the Applicability section of PRC-028-1 detailed in the SRC's response to question 5 below, the SRC recommends that Section 4.2 of the PRC-002-5 Applicability section be revised to refer to the entirety of Inclusion I2 instead of only referring to I2, Part (b).	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR is in support of the EEI comment.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) for this question and adopts them as its own.	
Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
The BES Reference Document, Version 3, August 2018, verbiage and clarifying illustrations indicate that I4 was created for IBRs, and that IBRs are included within scope only by I4 and not I2. Suggest either removing references to I2 in the proposed Applicability Section 4.2, or stating without specific inclusions, e.g., "... excluding inverter-based portions of generating plants/Facilities included in the BES by meeting the BES definition." Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
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	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
The changes make it clear that PRC-002 does not apply to IBR facilities.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The changes make it clear that PRC-002 does not apply to IBR facilities. The MRO NSRF would like to note the word "portions" in Applicability Section 4.2 may add confusion, consider if it can be removed or if other wording can be used.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees with the modification and understands the intent of the Standard Drafting Team (SDT); however, SIGE encourages the SDT to clarify the effects of the proposed changes to the NERC Glossary Definition and BES Reference Document.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	Yes
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
The changes make it clear that PRC-002 does not apply to IBR facilities.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	

Answer	Yes
Document Name	
Comment	
OPG supports the NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
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	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	

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	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
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 Bray - Arizona Electric Power Cooperative, Inc. - 1	
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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
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	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
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	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
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	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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	
Ruida Shu - Northeast Power Coordinating Council - 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	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michiko Sell - Pine Gate Renewables - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan	
Answer	
Document Name	
Comment	

No comments

Likes 0	
Dislikes 0	

Response

2. Do you agree with the need of creating a new Standard (PRC-028-1) to address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002?

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	
Comment	

PNMR supports EEI's comment related to not being in agreement of installing disturbance monitoring equipment at all IBR locations that conform to the BES definition is necessary, nor do we agree that the SAR authorized such an expansive scope.

Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	
Comment	

The NAGF supports creating the new Standard PRC-028 focused on inverter-based resource disturbance monitoring and reporting requirements, but does not agree that all IBR facilities need DME at the substation and on each feeder circuit. Please consider the effectiveness of the application of DME only at the substation/collector bus for IBR facilities rather than on each feeder, and of limiting the facilities to which the addition of DME is required as determined by the process outlined in Question 5 below.

There is already some ability, without the addition of DME at all IBR locations, to determine the causes of inverter reactions to HV system disturbances as demonstrated in the various disturbance reports which list the various type of responses that have been published.

Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	No
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the comments of the NAGF.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The long list of possible causes of the reactions found in the multiple disturbance reports from the past 5 years indicate that sufficient data is already available to determine what is occurring at the inverter level. From the multiple disturbance evaluation reports that have been written in the past 5 years, it appears that the reaction of the inverters to system disturbances has become well understood.

It is not apparent that every IBR plant will needs to have the added ability to evaluate the required data collected by the newly required monitoring specified. PRC-002-4 recognized that certain facilities are more significant to the reliability of the BES as indicated by the TO evaluation and TP evaluation included in Requirement R1 and R5 of that version. Extending this standard's requirements to all IBR facilities seems to be a bit of an over-reaction.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3

Answer	No

Document Name	
Comment	
NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	

Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The implementation timeframe should be 24 months or the NERC GO-IBR registration deadlines, whichever is greater.	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation recommends that the Standard Drafting Team consider a similar approach for PRC-028 as in PRC-002, requiring the TO and RC to identify areas within their regions that are susceptible to disturbances (or high concentration of IBRs) that would benefit from monitoring and recording capabilities. As opposed to a blanket requirement for ALL IRB facilities to install SER, FR, and DDR equipment.	

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports the NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation recommends that the Standard Drafting Team consider a similar approach for PRC-028 as in PRC-002, requiring the TO and RC to identify areas within their regions that are susceptible to disturbances (or high concentration of IBRs) that would benefit from monitoring and recording capabilities. As opposed to a blanket requirement for ALL IRB facilities to install SER, FR, and DDR equipment. 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 development of a new Reliability Standard to address gaps in disturbance monitoring of IBRs, however, we do not agree that installing disturbance monitoring equipment at all IBR locations that conform to the BES definition is necessary, nor do we agree that the SAR authorized such an expansive scope.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
AES Clean Energy supports the creation of PRC-028 to address gaps identified by the IRPTF.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
None	
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 for question #2.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: 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 supports the SDT decision to separate the Inverter-Based Resource requirements to avoid making PRC-002 overly complicated by trying to address both synchronous and IBRs in a single standard.

Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	Yes
Document Name	
Comment	
Ameren supports EEI's comments on this question.	
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	

The long list of possible causes of the reactions found in the multiple disturbance reports from the past 5 years indicate that sufficient data is already available to determine what is occurring at the inverter level. From the multiple disturbance evaluation reports that have been written in the past 5 years, it appears that the reaction of the inverters to system disturbances has become well understood.

It is not apparent that every IBR plant needs to have the added ability to evaluate the required data collected by the newly required monitoring. PRC-002-4 recognized that certain facilities are more significant to the reliability of the BES as indicated by the TO evaluation and TP evaluation included in Requirement R1 and R5 of that version. Extending this standard's requirements to ALL IBR facilities seems to be a bit of an over-reaction.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees with NAGF comments.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees with NAGF comments

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	Yes
Document Name	

Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy supports EEI's comments which state: EEI supports the development of a new Reliability Standard to address gaps in disturbance monitoring of IBRs, however, we do not agree that installing disturbance monitoring equipment at all IBR locations that conform to the BES definition is necessary, nor do we agree that the SAR authorized such an expansive scope.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	

Comment	
PRC-028 to include requirements for adequate monitoring of IBRs as shown necessary by operational experience. PRC-002 to remain in effect for synchronous based generation for a large-scale view of system reliability.	
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	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
PRC-028 to include requirements for adequate monitoring of IBRs as shown necessary by operational experience. PRC-002 to remain in effect for synchronous based generation for a large-scale view of system reliability.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	

PRC-028 to include requirements for adequate monitoring of IBRs as shown necessary by operational experience. PRC-002 to remain in effect for synchronous based generation for a large-scale view of system reliability.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

While AEP has no objections to creating a new standard specifically for IBRs, we are concerned by the content itself which we express in our response to Question 5.

Likes 0	
Dislikes 0	

Response

Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF

Answer	Yes
Document Name	

Comment

To the extent of monitoring only those IBRs that are connected directly to the BES.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michiko Sell - Pine Gate Renewables - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	Yes
Document Name	
Comment	
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 RSC

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

Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 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

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
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	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
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	

Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
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	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
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	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
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	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
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	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan	
Answer	
Document Name	
Comment	
Not applicable	
Likes 0	
Dislikes 0	
Response	

3. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF	
Answer	No
Document Name	
Comment	
I agree that PRC-002 -5 changes are cost effective. The new PRC-028-1 standard will increase costs significantly for those utilities that have installed IBRs prior to the standards effective date.	
Likes 0	
Dislikes 0	
Response	

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
The following unnecessary equipment requirements will lead to increased project cost. Section 2.2 2.1 PRC-002 does not require real and reactive power for FR data, the same should apply for PRC-028 2.2 There is limited value with FR data for IBRs and this requirement should be removed. 2.3 There is limited value with FR data for shunt or reactive devices and this requirement should be removed. -This section should also exclude IBRs that were installed prior to the approved standard. Only DDR or continuous data should be required on IBRs that were installed prior approval. Section 3 - The sample rate and record length requirements are not consistent with the requirements in PRC-002. The 128 samples per cycle recording rate and 2 second record length may not be supported by installed or available technology, especially for IBRs. Note- Vistra has been evaluating various technologies that we could use for IBRs and there are not many cost effective options for IBRs. Section 5 The output sampling rated of 60 times per second is not consistent with the 30 times per second requirement in PRC-002 Section 7 The time period for storing events is 30 days vs the 10 days in PRC-002. Not all equipment can store DDR or continuous data for 30 days.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

It has been recognized in past Technical Rationale documents for PRC-002, by members of their SDT, that requiring more than 10 days of granular data retention would be expensive and unnecessary. Requiring 30 days of data retention and provision would obviously be even more expensive than ten, making the proposed revisions unreasonable and not “cost effective.”

In addition, AEP has several other concerns with the cost impact of the new Standard PRC-028-1.

* AEP does not consider the inclusion of “at least one IBR unit connected to last 10% of each collector feeder length” in PRC-028 4.2.5 as cost effective. AEP questions the reliability benefit data these BES Elements will provide when considering the proposed changes to PRC-024 to a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances and the requirements of PRC-004, Protection System Misoperation and Correction.

* PRC-028 does not currently limit the applicability of required data, while PRC-002 provides criteria which limits the BES Elements that are required to have dynamic Disturbance recording data. Similar limitations should be placed on PRC-028 as well.

* PRC-004 excludes Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities. PRC-028 should be developed in alignment with PRC-004 by retaining these exclusions in PRC-028 in its present state, as well as in its future state.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

Cost effectiveness cannot be known at this time.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

The modifications made to PRC-002 are a zero-cost item. The costs associated with PRC-028 are substantial. Some IBR facilities have a single feeder into the 34.5kv collector bus while other sites may have 12 or more feeder circuits. Requiring monitoring on each feeder is excessive.

Requiring monitoring on wind facilities is not warranted as most of the disturbance events that have been studied have revealed that solar facilities are the most susceptible to reacting to system disturbances.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

Talen supports the comments of the NAGF.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

Cost effectiveness cannot be known at this time.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	
Comment	

Until FE understands the definition intent of inverter-based resources under these standards, we cannot determine the cost effectiveness of this project.

In addition, FE supports EEI's comments which state:

EEI is concerned that proposed PRC-028-1 does not align with the approved SAR scope and if approved would place unreasonable costs on registered entities without adequately balancing costs as required by the SAR. We further note that the SAR Scope states that "it is important that some of these resources and nearby BES elements are monitored with DDR devices to ensure adequate coverage for disturbance analysis while balancing cost impacts." The SAR does not intend that all IBR facilities need to have the level of monitoring proposed. To address this concern, the SDT should develop criteria that allows entities to select a representative number of sites in order to ensure adequate analysis of IBR performance.

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	
Comment	

BC Hydro thanks the drafting team for their efforts and appreciates the opportunity to comment.

PRC-028-1 Requirements are generally more stringent than PRC-002 requirements, particularly, fault recording (FR) sampling, FR triggering, FR length, CLK accuracy, and retrieval period requirements. Entities will have to assess if current PRC-002 monitoring solutions are capable of meeting technical requirements in PRC-028-1 as currently drafted, and may have to develop new monitoring systems if currently implemented solutions are unable to meet the increased requirements.

While the technical justification cites IEEE 2800-2022 as a basis for the requirements, it does not appear to identify instances where Disturbance Monitoring Equipment records meeting PRC-002 requirements would have been insufficient for event or disturbance analysis, which could justify increased technical requirements in PRC-028-1 Draft 1.

Requirement R3 asks for more data and it applies to all in scope IBR facilities, regardless of installation date whereas R1 and R2 have specific exemption criteria for existing units. Requirements R4, R5 specify DDR requirements similar to PRC-002; however as drafted these Requirements will be applicable to all in scope IBR facilities unlike Requirements R1 and R2.

BC Hydro suggests that technical requirements for PRC-028 be specified in line with PRC-002 requirements for IBRs installed prior to the effective date of the standard. This will still constitute an improvement over the status quo for availability and quality of records, while improving cost effectiveness of the proposed changes in PRC-028.

PRC-028-1 Requirements R1 and R2 provide an exemption to IBR units "installed" prior to the effective date of the Standard. Please provide clarity on the meaning of the term "install".

Likes 0	

Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation agrees with the PRC-002-5 cost but inverter base does not apply to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments:

It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement.

As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we strongly disagree with making this new standard inclusive of all IBR facilities regardless of risk to the BES.

It is our recommendation that PRC-028 take a similar approach as PRC-002-5 and allow the TO and RC to evaluate which IBR Facilities need SER, FR, and/or DDR capabilities installed. It is our opinion that a blanket approach is cost-prohibitive whereas a risk-based approach provides a reasonable level

of information and is much more cost-effective.	
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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO. The proposals will result in more time and $$ spent on unproductive activities. SDTs should be required to provide cost/benefit analysis and prove the reliability benefits of their proposals.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	

The proposals will result in more time and $$ spent on unproductive activities. SDTs should be required to provide cost/benefit analysis and prove the reliability benefits of their proposals. NO, NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
The proposals will result in more time and $$ spent on unproductive activities. SDTs should be required to provide cost/benefit analysis and prove the reliability benefits of their proposals.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
The proposals will result in more time and $$ spent on unproductive activities. SDTs should be required to provide cost/benefit analysis and prove the reliability benefits of their proposals. NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	

PRC-028 -The data sampling rates seem excessive and are a significant increase from the requirements in PRC-002. These sampling rates will prevent the use of protective relaying to satisfy the standard, which will increase cost burden.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

The modifications made to PRC-002 are a zero-cost item. The costs associated with PRC-028 are substantial. Some IBR facilities have a single feeder into the 34.5kv collector bus while other sites may have 12 or more feeder circuits. Requiring monitoring on each feeder is excessive.

Requiring monitoring on wind facilities is not warranted as most of the disturbance events that have been studied have revealed that solar facilities are the most susceptible to reacting to system disturbances.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The modifications made to PRC-002 are a zero-cost item. The costs associated with PRC-028 are substantial. Some IBR facilities have a single feeder into the 34.5kv collector bus while other sites may have 12 or more feeder circuits. Requiring monitoring on each feeder is excessive. It is estimated that it will cost $300-450k to install DFR equipment on each collection system feeder; with an aggregate cost of $4.2-$6.4 million just for that wind generation asset with at least 14 collection system feeder circuits. The MRO NSRF recommends limiting applicability to only facilities that have experienced reportable events where clear causes have not been identified and limiting the monitoring location to the BES collection bus. Another costly part depends on how exclusions are handled for older less capable equipment in PRC-028-1 R1, R2 and R3.

Requiring monitoring on wind facilities is not warranted as most of the disturbance events that have been studied have revealed that photo-voltaic facilities are the most susceptible to reacting to system disturbances.

Likes 1	JEA, 1, McClung Joseph

Dislikes 0	
Response	
Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
The SAR Scope states that “it is important that **some of these resources and nearby BES elements are monitored with DDR devices** to ensure adequate coverage for disturbance analysis while balancing cost impacts.” However, the SAR does not intend that all IBR facilities need to have the level of monitoring proposed. To address this concern, the SDT should develop criteria that allows entities to select a representative number of sites in order to ensure adequate analysis of IBR performance. Requiring monitoring at all IBR facilities would result in unnecessary costs without improving reliability.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	

Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

SMUD and BANC believe that the new Standard PRC-028-1 is not cost effective and we support the comments submitted by Southern Company.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	

Comment

PG&E supports the input provided by the NAGF and EEI on the potential costs of the proposed modifications.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	

Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
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	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #3.

In addition, Evergy estimates that the cost of installing DFR equipment on the high side of a pad mounted transformer at the base of a wind turbine in the last 10% of an existing wind turbine feeder will be $300-450k or 2-3 times the cost of installing the same equipment in an existing substation. For example, one wind farm has 14 feeders so installing this equipment on every feeder there would cost an estimated $4.2-6.3 million dollars for that one facility.

EIA data shows that there are currently 604 wind farms with a size of 75 MW or greater with a total 975549 MW capacity. Assuming there is a feeder for every 10-20 MW worth of wind turbines and the estimate per installation, the range between $1.463-$2.195 billion dollars just to install these at the end of every feeder and does not include the substation installations that would be required. This estimate is only for feeders at wind turbines and does not include any estimates for solar farms or other IBRs so the total cost could likely be double or triple this estimate. This expense has minimal or no direct benefit to grid reliability and will increase electricity costs for everyone across North America in a quest for better data. Evergy highly suggests that the drafting team consider limiting the scope of DFR installations to areas that are identified by an RC similar to what is done in PRC-002.

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	No
Document Name	

Comment

It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement.

As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we strongly disagree with making this new standard inclusive of all IBR facilities regardless of risk to the BES.

It is our recommendation that PRC-028 take a similar approach as PRC-002-5 and allow the TO and RC to evaluate which IBR Facilities need SER, FR, and/or DDR capabilities installed. It is our opinion that a blanket approach is cost-prohibitive whereas a risk-based approach provides a reasonable level of information and is much more cost-effective.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

We recommended the drafting team consider the establishment of a minimum MW threshold to ensure very small installations, such as those that may be considered BES due to co-location with synchronous machines, are excluded to ensure cost-effectiveness.

Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

There should not be any cost associated with the modifications made in PRC-002-5. However, costs associated with PRC-028-1 are substantial. Depending on the configuration and equipment capability of existing operational IBR facilities, the costs associated with retrofitting hardware, software and labor will run into 6 figure amount for a single IBR site.

Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	

The PRC-002-5 changes are cost effective.

PRC-028-1 is not cost effective and should align more with the requirements of PRC-002. Specifically, PRC-028 should be consistent with the PRC-002 data retrievability period of 10 calendar days instead of 30 calendar days (PRC-028 R7.1) especially for DDR data. PRC-028 should also let the TO and RC evaluate (as was done in PRC-002) which IBR Facilities need SER, FR, and/or DDR capabilities installed, instead of including all IBR facilities regardless of risk to the BES. PRC-028 should also follow PRC-002 FR requirements which do not require real and reactive power for FR data (PRC-028 R2.1.3) and have a minimum sample rate of 16 samples per cycle instead of 128 samples per cycle (PRC-028 R3.2.2). PRC-028 should

also be consistent with PRC-002 DDR requirements for an output recording rate of electrical quantities of at least 30 times per second instead of 60 times per second (PRC-028 R5.2).

Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	No
Document Name	
Comment	
It will be costly to implement.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power's comments are aligned with those of the MRO NSRF and EEI for this question. Minnesota Power reiterates that PRC-028 would result in substantial costs for entities and disagrees with the proposal to monitor all IBR facilities.	
Likes 0	
Dislikes 0	
Response	
Michiko Sell - Pine Gate Renewables - 5	
Answer	No
Document Name	
Comment	

We are concerned that the cost and burden of the proposed PRC-028 requirements are not justified by the reliability benefits it would provide. We believe the costs and benefits of the proposed standard can be better balanced by a. only requiring data collection at generating plants larger than 500 MVA, b. requiring data collection on a single collector feeder or IBR unit instead of every collector feeder or IBR unit in the plant, and c. only applying the data collection requirements to plants that sign an interconnection agreement after the effective date of the standard. Only applying the requirements to a single IBR unit and to larger plants will make PRC-028 more comparable to the PRC-002 companion standard for synchronous generators, avoiding undue discrimination against Inverter-Based Resources (IBRs).

Regarding potential reliability benefits of the proposed standard, we agree that ride-through issues at some IBRs have presented a legitimate reliability concern. However, the recent adoption of Federal Energy Regulatory Commission (FERC) Order 2023 directly addresses many of those concerns by imposing mandatory requirements to fully ride-through grid disturbances and to accurately validate models of plant performance at the sub-second transient timescale. Prior to the adoption of Order 2023, the proposed requirements of PRC-028 may have provided a significant reliability benefit by improving understanding of the ride-through performance of IBRs, and thus helping to identify solutions to any concerns. However, now that FERC Order 2023 already solved many of those concerns by requiring ride-through performance and accurate modeling of sub-second plant performance, it is not clear what reliability benefit PRC-028 might provide.

The proposed PRC-028 requirements would impose a considerable cost and burden on generators. While R1 and the 2.2.3. subpart of R2 that requires fault recording for “DC bus current and voltage” have an exemption that “IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded,” but R3 and the other parts of R2 appear to apply retroactively to all IBR plants. Retroactive requirements impose a much greater financial burden on the generator as those costs cannot typically be recovered once a power purchase agreement has been signed, and the cost and implementation burden for retrofits is typically much higher than if the data collection equipment were planned and installed as part of initial plant construction. Moreover, retroactive requirements set a bad precedent and introduce regulatory uncertainty that makes generation investment more challenging and risky, and thus costly. In some cases the cost of installing the required data collection, storage, and transmission equipment and associated auxiliary equipment could approach $1 million per plant, in addition to ongoing operations and maintenance and compliance costs associated with that equipment. The requirement in R3 for the fault recorder at each IBR unit (which footnote 2 defines as each inverter or wind turbine generator) to report at least 128 samples per cycle for over two seconds per event necessitates the use of expensive high-speed sensing equipment at each IBR unit, and requires each recorder to capture, store, and transmit at least 15,000 datapoints per event.

To make the cost of PRC-028 more reasonable while preserving the value of the proposed data collection, as well as avoiding undue discrimination against IBRs relative to synchronous generators, we suggest that data collection in PRC-028 only be required prospectively and not retroactively, and only at plants that are 500 MVA and greater, which is the plant size threshold at which synchronous generator data collection is required in the PRC-002 standard. If the TO or RC/PC can compellingly demonstrate that smaller new plants should be required to comply with PRC-028’s data collection requirements due to local reliability concerns, such as weak grid issues or high penetrations of IBRs in a local area, then that should be allowed.

In addition, the cost of installing a sequence of event recorder and fault recorder on the last 10% of each collector feeder per R1 and R2 is significant, as large IBR plants can each contain dozens of collector feeders. Moreover, the fact that IBR plants typically consist of multiple collector feeders with similar if not identical equipment connected to them casts further doubt on the value of installing data collection devices on each collector feeder, as the impact of the disturbance and the IBR response is likely to be similar if not identical across those feeders. Even more burdensome is that R3 requires fault recorders to be installed at each IBR unit, which footnote 2 defines as each inverter or wind turbine generator. IBR plants typically consist of dozens if not hundreds of IBR units that are essentially identical. As a result, a more reasonable requirement would be for data collection equipment to be installed on a single collector feeder or IBR unit at each plant, which should allow extrapolation of that data to other collector feeders or IBR units at the plant. If a plant contains multiple types of inverters or wind turbine generators, it may be reasonable to require data collection on each feeder or unit that uses a different inverter or generator type.

Given that there are finite resources for complying with all NERC requirements, and in light of the fact that the ride-through concerns PRC-028 is attempting to understand have already been addressed by FERC Order 2023, we are concerned that PRC-028 as proposed could actually undermine reliability by distracting from more pressing reliability needs. We believe the revisions we have proposed will result in a standard that better balances the cost of complying with standard with its reliability benefit.

Likes 0	
Dislikes 0	

Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF notes that the cost to purchase and install monitoring equipment will vary by company. NAGF members estimates range from $100,000 to $450,000 per feeder at an IBR generation facility. High end estimate is based on having to build a new structure to house the equipment, get power and communications to it, and digging up the collector circuit to connect the equipment. Lower estimate is based on installing the recording equipment within the IBR unit, leveraging the use of existing instrument transformers, and integrating I/O from existing IBR OEM control systems. Note that having to install monitoring equipment to the IBR unit connected to last 10% of ***each*** *collector feeder length (i.e., furthest from the collector bus) in an IBR generation facility will be expensive; a wind farm that has 14 feeders, installing DFR equipment just on those 14 feeders at that single Facility, would have an estimated cost of between $1,400,000 – $6,300,000. Modifications would also be needed for the associated substation to install additional metering and RTACs (along with programming work), communication wiring, etc. Considering the number of existing BES IBR generation facilities, the cost would be in the billions of dollars to install. The concern is that the reliability benefit of installing such equipment does not justify the cost.*	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI is concerned that proposed PRC-028-1 does not align with the approved SAR scope and if approved would place unreasonable costs on registered entities without adequately balancing costs as required by the SAR. We further note that the SAR Scope states that “it is important that **some of these resources and nearby BES elements are monitored with DDR devices** to ensure adequate coverage for disturbance analysis while balancing cost impacts.” The SAR does not intend that all IBR facilities need to have the level of monitoring proposed. To address this concern, the SDT should develop criteria that allows entities to select a representative number of sites in order to ensure adequate analysis of IBR performance.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	

Comment	
Constellation is concerned about the possible cost involved in implementing the Fault Recording (FR) sampling rate that PRC-028 is requiring. SEL-300 series relays are used extensively throughout the industry and do not meet the required sampling rate proposed by PRC-028. If PRC-028 is approved with these required parameters many BES IBR facilities would be required to upgrade to SEL-400 series relays. This wholesale replacement for relay types would also require planned outages to facilitate. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR is in support of the EEI comment.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation is concerned about the possible cost involved in implementing the Fault Recording (FR) sampling rate that PRC-028 is requiring. SEL-300 series relays are used extensively throughout the industry and do not meet the required sampling rate proposed by PRC-028. If PRC-028 is approved with these required parameters many BES IBR facilities would be required to upgrade to SEL-400 series relays. This wholesale replacement for relay types would also require planned outages to facilitate. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Because of the reliability need to assess IBR performance during disturbances, the use of current fault recorder technology and associated cost of installation is the best solution. The staged implementation plan also allows entities five (5) years to implement changes so as not to overwhelm the supply chain or overburden staff resources. Please note ERCOT is a member of the ISO RTO Council Standards Review Committee but for their own reasons elect not to support this response to Question #3.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
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	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
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	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
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	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
Cost effectiveness cannot be known at this time.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	

Answer	
Document Name	

Comment

Duke Energy's focus is to assure the effective and efficient reduction of risks to the reliability and security of the grid and will not provide comments on the cost effectiveness of the proposed changes.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

WECC will not comment on the cost effectiveness, but will leave that to applicable entities.

Likes 0	
Dislikes 0	

Response

Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan

Answer	
Document Name	

Comment

No comments

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment	
CenterPoint Energy Houston Electric, LLC will abstain from answering Question 3.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports the NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Although PRC-028 Implementation Plan mirrors the existing PRC-002-1 Implementation Plan, PRC-028 will require all BES IBRs to install DME. Depending on the number of BES IBR locations owned by the GO, this could possibly result in numerous new DME installations that will be more challenging to coordinate and schedule compared to the implementation of PRC-002-1. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR requests review of revised PRC-002 and PRC-028 prior to agreeing to the implementation plan.	
Likes 0	

Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	
The Implementation Plan should explicitly require any new interconnected facilities that fall under the PRC-028-1 Applicability section to be compliant on or before the date of commercial operations. There is no need to stage the phase-in over 5 years for new construction.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Although PRC-028 Implementation Plan mirrors the existing PRC-002-1 Implementation Plan, PRC-028 will require all BES IBRs to install DME. Depending on the number of BES IBR locations owned by the GO, this could possibly result in numerous new DME installations that will be more challenging to coordinate and schedule compared to the implementation of PRC-002-1. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF provides the following implementation plan comments for consideration:

a. General: Request the SDT to consider revising the Implementation Plan to address when a new IBR generation facility is to be compliant with PRC-028-1.

b. Page 2, "Compliance Date for PRC-028-1 Requirements R1-R7" section:

i. Recommend revising the first paragraph such that the time period for 100% of an entities IBR generation facility to be compliant is three (3) years instead of the proposed two (2) year time limit.

ii. Recommend deleting the third paragraph as it does not provide any value for the implementation plan.

Likes 0	
Dislikes 0	

Response

Michiko Sell - Pine Gate Renewables - 5

Answer	No
Document Name	

Comment

For PRC-028 we are concerned with availability of needed devices for installation. Consider adding an additional traunch and extend full implementation by a year. Also consider MW size of Facilities since this is a reliability assurance issue.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power agrees with the PRC-002-5 implementation plan.

For the PRC-028-1, Minnesota Power's comments are aligned with the MRO NSRF and suggest a time frame of 6 calendar years to meet the 100% requirement.

Likes 0	
Dislikes 0	

Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Concerns about PRC-028 applicability and data requirements will need to be addressed before the implementation plan can be supported.	
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	No
Document Name	
Comment	
It is ACES' opinion that the proposed changes to PRC-002 are minimal; therefore, the timeline identified in the Implementation Plan is appropriate. As for the proposed timeline for PRC-028-1 R1-R7 identified in the Implementation Plan, it is ACES' opinion that the timelines identified for 50% and 100% compliance should be equal. We recommend the following change: "…fully compliant at 100% of their generating plant/Facilities within six (6) calendar years of the effective date of Reliability Standard PRC-028-1." Lastly, while an individual entity's compliance with a given requirement is auditable, their strategy for how they will manage their compliance is not auditable. Therefore, the requirement that an entity share their implementation strategy for PRC-028-1 R1-R7 with the ERO Compliance Monitoring and Enforcement Program staff should be struck from the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	No
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	

Comment

PG&E does not support the time frame in the current implementation plan without an exception (see the input to Question 5, item #1 below) for existing applicability to facilities at the Transmission Owner (TO) Point of Interconnection (POI).

An exemption clause is given to preexisting IBR facilities (GO). At present, no TO exemption exists at the Point of interconnection. This requires installation of equipment, or replacement of existing equipment, at the POI for all identified IBR facilities. We recommend providing a TO exemption similar to that granted for GO, particularly if the bus had been identified under PRC-002 and has equipment installed to comply with PRC-002. An alternative is to make PRC-028 FR/SER/DR performance requirements identical to PRC-002.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the comments of the NAGF.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The PRC-002-5 implementation plan is fine as proposed (immediate) since the previous requirements did not change for the synchronous units.

The two partitions of completion proposed, 50% & 100%, should be given equal time periods since the %'s are split in half - that is, the 100% time period should be "within six (6) calendar years of the effective date of PRC-028-1" (rather than in 5 calendar years).

Entities should not have to share their strategy for implementation with the ERO Compliance Monitoring and Enforcement Program staff. This requirement should not be in the implementation plan.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

The PRC-002-5 implementation plan is fine as proposed (immediate) since the previous requirements did not change for the synchronous units.

The two partitions of completion proposed, 50% & 100%, should be given equal time periods since the %'s are split in half - that is, the 100% time period should be "within six (6) calendar years of the effective date of PRC-028-1" (rather than in 5 calendar years).

Entities **should not** have to share their strategy for implementation with the ERO Compliance Monitoring and Enforcement Program staff. This requirement should not be in the implementation plan.

The 100% compliant date given for R8 doesn't make sense because there may not be any DME installed at the time specified.   Consider using this, "R8 is be applicable to each DME installation upon completion of the installation and commissioning of the DME equipment."

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3

Answer	No
Document Name	

Comment

NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the MRO NSRF comments.	

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments:

It is ACES' opinion that the proposed changes to PRC-002 are minimal; therefore, the timeline identified in the Implementation Plan is appropriate.

As for the proposed timeline for PRC-028-1 R1-R7 identified in the Implementation Plan, it is ACES' opinion that the timelines identified for 50% and 100% compliance should be equal. We recommend the following change:

"…fully compliant at 100% of their generating plant/Facilities within six (6) calendar years of the effective date of Reliability Standard PRC-028-1."

Lastly, while an individual entity's compliance with a given requirement is auditable, their strategy for how they will manage their compliance is not auditable. Therefore, the requirement that an entity share their implementation strategy for PRC-028-1 R1-R7 with the ERO Compliance Monitoring and Enforcement Program staff should be struck from the Implementation Plan.

Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	

Black Hills Corporation agrees with NAGF comments.

Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	

Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	

Comment	
Reclamation supports a 18-month implementation time frame.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
Given BC Hydro's comments to Question #3 above, and pending additional clarifications, BC Hydro is unable to support the proposed Implementation Plan at this stage.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
Entities should have to submit a plan that is approved by the Region as being reasonable. It is difficult to determine the number of facilities and how much equipment may have to be addressed by companies that will be impacted. Timelines are clean, but do not always represent the real-life situations that must be addressed.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	

Comment	
Until the definition of inverter-based resources is clearly defined, then FE would be supportive of the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Talen supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The PRC-002-5 implementation plan is fine as proposed (immediate) since the previous requirements did not change for the synchronous units. The two partitions of completion proposed, 50% & 100%, should be given equal time periods since the %'s are split in half - that is, the 100% time period should be "within six (6) calendar years of the effective date of PRC-028-1" (rather than in 5 calendar years). Entities should not have to share their strategy for implementation with the ERO Compliance Monitoring and Enforcement Program staff. This requirement should not be in the implementation plan. The 100% compliant date given for R8 doesn't make sense because there may not be any DME installed at the time specified. Consider using this, "R8 is applicable to each DME installation upon completion of the installation and commissioning of the DME equipment."	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Until further clarifications are provided regarding our expressed concerns, AEP would be unable to support a proposed Implementation Period.	
Likes 0	
Dislikes 0	
Response	

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
With the timline provided it may be difficult to procure proper equipment in time to meet requirements.	
Likes 0	
Dislikes 0	
Response	

Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF	
Answer	No
Document Name	
Comment	
The implementation plan for PRC-028-1 is to short of a time frame. 50% within in 3years won't happen due to industry wide material and equipment shortages and delays. Implementation should be extended to at least a minimum of 7 years at 50%.	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports the NPCC RSC’s comments.	
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 phased Implementation Plan.

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	Yes
Document Name	
Comment	
Ameren supports EEI's comments on this question.	

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	

Comment

Phased implementation plan is acceptable.

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

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	

Comment

Phased implementation plan is acceptable.

Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Phased implementation plan is acceptable.	
Likes 0	
Dislikes 0	
Response	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
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 RSC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
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	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
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	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
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	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 5,6

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

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

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	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	

5. Provide any additional comments for the standard drafting team to consider, if desired.

Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF	
Answer	
Document Name	
Comment	
PRC-028-1 should state clearly how to determine if IBRs are capable of recording or not. IBRs downstream of a feeder shouldn't be monitored as they aren't BES assets.	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	
Document Name	
Comment	
Section 1.2. Agree with the exclusion for IBRs that are currently installed. No issues with IBR fault codes, alarms, etc but the operating mode, voltage/frequency ride-through, and control system values are either static configuration parameters or operational values which are not sequence of event points. Section 4. Agree with section 4 and it is the most important for analyzing localized or wide spread events.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
While AEP supports the efforts of the Standards Drafting Team and their overall direction in Phase II, we are concerned by what we perceive as an excessiveness of data granularity, especially when compared to those of synchronous machines in PRC-002. The follow items are of specific concern. 1) R3.1.2. – We see no justification for, nor reliability benefit in, requiring a minimum recording rate of 128 samples per cycle. The sample rate is eight	

times greater than that used for synchronous machines in the equivalent requirements of PRC-002, and far exceeds the maximum sampling rate of many relay models currently used. AEP would like to suggest instead using 16 samples per cycle.

2) Subparts of R1.2 – AEP questions the reliability benefit in requiring the data specified in the subparts, which includes data not captured as "sequence of events." In addition, why would this data be necessary for IBRs but not for synchronous machines?

AEP also questions the necessity of providing the data as several projects are currently underway to address the impact IBRs have had on the BES. The purpose of Project 2020-02 is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Specifically, this SAR focuses on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. The SAR also ensures protection or controls that fail to ride through system events are analyzed, addressed with a corrective action plan (if possible), and reported to necessary entities for situational awareness.

3) 7.1 through 7.5 – As currently written, the requirements set no expectations to encourage a timely request for data, which may put data availability at risk. The Technical Rationale states "if a request for the data is made on Day 31, that is outside the 30 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data", however this is not made explicitly clear within the requirements themselves. In addition, recording devices often save and discard data using a "first in / first out" methodology, so thirty full days of meaningful data may not be available if a request is made several weeks after an event. The obtainer of the data needs ample opportunity to retrieve the data after the request, and if a request is made at the end of the allowable 30 day window, it is very possible that some of the desired data may no longer be available. The data at most risk for omission would be pre-event data as well as data at the time of the event. As a result, data "inclusive of the day the data was recorded" may no longer be available. To address the core of our concerns, clarity is needed regarding the standard's expectations regarding the minimum time period that a device is expected to retain historical information. As currently written, the standard seems to infer that a device might need to retain as many as 60 days of data in order to properly fulfill a request made 30 days after an event occurs. In addition, there is no specificity given regarding how much of the 30 days of data provided be either pre- or post-event.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

NA

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment	
AECI supports the drafting teams approach to PRC-002 and PRC-028 except for the creation of standard specfic defined terms for "inverter based resource (IBR)" and "IBR unit". Currently there are at a minimum of 8 active NERC projects under development to address various IBR reliability issues, multiple projects contain inconsistent standard specific defined terms for IBR and IBR unit. NERC should coordinate with industry to develop BES glossary terms for IBR and IBR unit and apply the terms to all applicable standards.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
A) Applicability section 4.2.5 is confusing. Is this facility item attempting to identify the required locations for DME to be added? If so, this is out of place and needs to be addressed in a requirement rather than in the applicability section only as is done in R1, 1.2. B) In requirement R1 sub-parts 1.2.4 and 1.2.5, it is not clear what is desired to be recorded in the SER data. C) There are multiple control systems in play at these facilities - Requirement R1, sub-part 1.2.6 needs to be very specific to which control system, which command value, which reference value, and which feedback signals are required to be monitored. Further, these signals are not well suited for SER recording, which typically are dry contact inputs used to determine the order of events rather than the time-variation of control and process variables. D) Requirement sub-parts 3.1.3, 3.2.3, and 3.3.3 need to specify values to be considered as an (ac/dc) overvoltage condition, (ac/dc) undervoltage condition, (ac/dc) overcurrent condition, dc reverse current condition, over frequency condition, underfrequency condition. E) The inclusion of NERC as a recipient of information upon a request is not appropriate. NERC has other means of obtaining information that should be used, including Section 1600 data requests or NERC Alerts.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

NERC Alert R-2023-03-14-01 Level 2 – Inverter-Based Resource Performance Issues (NERC Alert) and NERC Project 2021-04 PRC-028-1 (PRC-028-1) information appear to not align. For example:

(a) NERC Alert information appears to be missing from SER/FR/DFR data requests. Is any of the following information needed to perform wide area analysis, fault analysis, other? While the following three items may possibly be included as specifications required in interconnect agreement data, are they also needed for PRC-028 requirements?

• Active Power Ramp Rate (after momentary cessation)

• Recovery time delay

• Momentary Cessation- if in use- (may be covered by fault alarm (1.2.2) and operating mode change (1.2.3)

(b) Are the below listed signals intended to be covered by R1.2.6 Control system command values, reference values, and feedback signals of the new 28 standard? Are they values that will impact the analysis performed by the RCs and BAs? The following were of concern in the NERC Alert:

• frequency tripping time delay

• frequency tripping inhibit (if used)

• droop performance-this is affected by FERC Order No. 842

• Indication if ramp rate is being controlled by individual unit versus by plant level controller

• Typically, if plant voltage level falls below its continuous operating range the individual inverters control operation – *does this constitute a change in operating mode as covered in R1.2.3?*

• Maximum Power Point Tracking (MPPT) controls (if MPPT function was frozen to pre-contingency value or reset to default).

(c) The NERC Alert highlights the following items. Should they be included in PRC-028-1 as triggers:

• Inverter Instantaneous AC Voltage tripping

• Inverter Instantaneous AC overcurrent

• Inverter phase lock loop loss of sync

• Inverter DC unbalance tripping

Are any point of measure (POM) or point of interconnect (POI) triggers besides the following needed:

• 3.1.3.1. Neutral (residual) overcurrent and

• 3.1.3.2. AC phase overvoltage and undervoltage

Likes 0	

Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	
Document Name	

Comment

Talen supports the comments of the NAGF.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

FE supports EEI's comments which state:

EEI Comments on PRC-028-1:

Purpose Statement: EEI does not agree that the purpose statement for this Reliability Standard aligns with the intended scope of this project. To address this concern, we offer the following edits in boldface:

To have adequate data available from **a representative number of** inverter-based resources (IBR)**/Facilities** to facilitate **the** analysis **of IBR performance during** Bulk Electric System (BES) Disturbances.

Functional Entities: EEI does not agree with the Functional Entities as listed. We believe that PRC-028 should also include Reliability Coordinators (RC) in this list, noting that the SAR was never intended to require monitoring of IBRs at all locations. Instead, the SDT should develop a criteria for identifying where and when monitoring should be installed and the RC should be the entity that 1) utilizes that criteria to determine where monitoring is needed and 2) notifies owners of their obligations.

Applicability Section: EEI does not agree with the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in the BES Definition, Inclusion I2. (See EEI comments for Question 1)

All Requirements: EEI does not agree that this project was intended to monitor all IBRs or IBR Facilities. In the SAR it clearly states that the intent is to install DDR at some locations, not all locations. The SAR also stated that the requirements were to be balanced against costs which given the magnitude of the proposed requirements, it is difficult to see where costs were adequately balanced.

Likes 0	

Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Reclamation does not agree with the modifications to the wording of BES Elements in R6 and R7 in the "Violation Severity Levels" section. 'Element' is sufficiently defined in the NERC Glossary of terms and 'BES Element' encompasses the required equipment (elements) for Disturbance Monitoring. Reclamation recommends keeping the original wording "for all applicable BES Elements". Reclamation concurs that all IBR resources should have and maintain their own separate standards.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	

Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC has signed on to ACES comments: Firstly, Section 4.2 of the proposed Reliability Standard PRC-028-1 is somewhat confusing and seems to be a bit redundant; specifically, sections 4.2.1 and 4.2.5. It appears that these specific sections are dictating where specific equipment should be installed in addition to the locations specified in the various requirements of the standard. We recommend using an approach similar to the one used in PRC-002-5 Section 4.2. To accomplish this, we recommend using the following verbiage:	

"BES Elements associated with inverter-based portions of generating plants/Facilities meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition."

Secondly, Requirements 1.2.4 and 1.2.5 are unclear as to what values are to be recorded. We recommend that additional clarification be made to these sections.

Thirdly, Requirement 1.2.6 seems to be out of place. In a typical Sequence of Event Recording setup digital inputs are used to determine the specific sequence of occurrence for recorded events. The signals identified in Requirement 1.2.6 are typically analog signals that vary over time in response to process conditions. We recommend either removing this requirement altogether or being much more specific as to what information should be collected and how.

Lastly, we disagree with the approach that NERC should be able to request information from an entity directly via a Reliability Standard requirement. Please note that we are not opposed to NERC requesting this information nor do we think it is inappropriate for NERC to receive said data. We do however disagree with the method of collection. It is our opinion that NERC should utilize the existing data collection mechanisms (i.e. Section 1600 data requests, NERC Alerts, etc.).

Thank you for the opportunity to 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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	
Document Name	

Comment

Tacoma Power supports the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	
Document Name	

Comment

PRC-028 - If the point of 4.2.5 is to monitor the individual inverter performance prior to being summed into a collector system, I would consider mandating the last IBR on each feeder is monitored, rather than one of the IBR units in the last 10% of each feeder.

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

A) Applicability section 4.2.5 is confusing. Is this facility item attempting to identify the required locations for DME to be added? If so, this is out of place and needs to be addressed in a requirement rather than in the applicability section only as is done in R1, 1.2.

B) In requirement R1 sub-parts 1.2.4 and 1.2.5, it is not clear what is desired to be recorded in the SER data.

C) There are multiple control systems in play at these facilities - Requirement R1, sub-part 1.2.6 needs to be very specific to which control system, which command value, which reference value, and which feedback signals are required to be monitored. Further, these signals are not well suited for SER recording, which typically are dry contact inputs used to determine the order of events rather than the time-variation of control and process variables.

D) Requirement sub-parts 3.1.3, 3.2.3, and 3.3.3 need to specify values to be considered as an (ac/dc) overvoltage condition, (ac/dc) undervoltage condition, (ac/dc)overcurrent condition, dc reverse current condition, overfrequency condition, underfrequency condition.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	2021-04.PNG

Comment

1. PRC-028 applicability section 4.2.5 is confusing. Is this facility item attempting to identify the required locations for DME to be added? If so, this is out of place and needs to be addressed in a requirement rather than in the applicability section only as is done in R1, 1.2.

2. PRC-028 in requirement R1 sub-parts 1.2.4 and 1.2.5, it is not clear what is desired to be recorded in the SER data.

3. There are multiple control systems in play at these facilities – PRC-028 Requirement R1, sub-part 1.2.6 needs to be very specific to which control system, which command value, which reference value, and which feedback signals are required to be monitored. Further, these signals are not well suited for SER recording, which typically are dry contact inputs used to determine the order of events rather than the time-variation of control and process variables.

4. PRC-028 Requirement sub-parts 3.1.3, 3.2.3, and 3.3.3 need to specify values to be considered as an (ac/dc) overvoltage condition, (ac/dc) undervoltage condition, (ac/dc)overcurrent condition, dc reverse current condition, overfrequency condition, underfrequency condition.

5. The inclusion of NERC as a recipient of information upon a request is not appropriate. NERC has other means of obtaining information that should be used, including Section 1600 data requests or NERC Alerts.

6. For SER data in R1.2 (PRC-028), what is acceptable proof of exclusion for IBR units installed prior to the effective date of this standard and not capable of recording this data?

7. In PRC-028 it is recommended there be an exclusion similar to R1.2 for FR data in R2.2 and R3.2 for IBR units installed prior to the effective date of this standard that are not capable of recording this data with the required triggering, length, or sample rate. If permitted, what is acceptable proof of exclusion?

8. In PRC-028 it is recommended there be an exclusion similar to R1.2 for FR data in R2.3 and R3.3 for dynamic reactive units installed prior to the effective date of this standard that are not capable of recording this data with the required triggering, length, or sample rate? If permitted, what is acceptable proof of exclusion?

9. In PRC-028 for SER and FR data in sections R1.2, R2.2, R2.3, R3.2 and R3.3, please clarify the exclusion applies if only some data recording capability is available but not all data that the data that is available. It seems cleaner to exclude these units completely rather than use a more complex piecemeal method which may be difficult to audit.

10.Would the following situation be considered a possible violation in PRC-028? There is a discovery of recorder failure as noted may occur in R8 during a time when data was requested per R7?   (recorded data is not available due to the failure)

11. The PRC-028-1 technical rationale on page 2 states: “*The standard is only applicable to Transmission Owner in case where Transmission Owner owns equipment within the IBR Plant.” Should “equipment” be clarified that it is applicable to monitored elements such as breakers, transformers, reactive units or IBRs?*

12. Review the two figures called scenario 1 and scenario 2 and clarify PRC-028 applicability. Consider that Trans owner bus may or may not be applicable for PRC-002.

Consider if there may be a registration or information gap where (GO) IBR/wind/solar owners that are less than 75MVA may need to comply with PRC-028 due to the >75MVA aggregation threshold.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	
Document Name	
Comment	

Ameren would like more clarification around R2.2, specifically the phrase “IBR unit connected to 10% of each collector feeder length.”

2.2.3: Are they referring to a DC collection system as opposed to a DC to AC conversion at each wind turbine or solar panel? Ameren is confused as to how we would collect this data.

Ameren also supports EEI's comments on this question.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	

Comment

As stated in our response to question 3 above, AZPS does not agree that the SAR intended that all IBR facilities should be monitored. Instead, there should be a criteria for identifying where and when monitoring should be installed similar to PRC-002 and the RC should be the entity that determines where monitoring is needed and notifies owners of their obligations.

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

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	

Document Name	
Comment	

WEC Energy Group supports the additional comments provided by the NAGF.

Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	
Comment	

In PRC-002-5 Attachment 1, Bulk Electric System (BES) is spelled out in step 1 despite the acronym being used earlier in the Attachment and SER and FR acronym description are removed. All 3 terms are spelled out and acronyms identified in PRC-002-4 standard. Acronyms only are sufficient for all 3 in Attachment 1.

In Figure 2 of the PRC-028-1 Technical Rationale, it is clear the TO breaker on the generator tie line is not applicable. Please clearly identify this in the applicability section of the standard to avoid confusion between GOs and TOs for 4.2.1

Add a figure of an IBR interconnection without local high-side transformer breaker to the transmission system via transmission line to a Transmission Owner Ring Bus Substation. Clarify that the Transmission owner ring breakers do not have PRC-028-1 SER/FR responsibilities.

Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: 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 has the following additional input:

1 – PG&E believes the current wording of Requirement R1, Part 1.2 provides an exception for the Generator Owner (GO) for units installed prior to the effective date of the standard but is not clear the exception would be provided to the Transmission Owner (TO). This is based on the text of "… IBR unit

connected to the last 10% of each collector feeder length.” This implies that it applies to the GO since they would be part of the last 10% of the feeder length.

To indicate that exemption applies to both the GO and TO, PG&E suggests the following:

Take the text “IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded”, remove it from Part 1.2, and make it a footnote to the main R1 text. This would clearly indicate the exemption is for both the GO and TO.

2 – PG&E supports the NAGF input for Question 5 regarding having a methodology like PRC-002 to determine if SER/FR equipment are required verses the current draft approach of requiring all BES facilities to have the equipment.

3 – PG&E believes the PRC-028 recorder specification (sampling rate, etc..) are more stringent then PRC-002. PG&E recommends that PRC-028 should be brought into alignment with what is indicted in PRC-002.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan

Answer	
Document Name	

Comment

Not applicable

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6

Answer	
Document Name	

Comment

Dominion Energy supports EEI comments

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI.

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	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #5.

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

Firstly, Section 4.2 of the proposed Reliability Standard PRC-028-1 is somewhat confusing and seems to be a bit redundant; specifically, sections 4.2.1 and 4.2.5. It appears that these specific sections are dictating where specific equipment should be installed in addition to the locations specified in the various requirements of the standard. We recommend using an approach similar to the one used in PRC-002-5 Section 4.2. To accomplish this, we recommend using the following verbiage:

“BES Elements associated with inverter-based portions of generating plants/Facilities meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition.”

Secondly, Requirements 1.2.4 and 1.2.5 are unclear as to what values are to be recorded. We recommend that additional clarification be made to these sections.

Thirdly, Requirement 1.2.6 seems to be out of place. In a typical Sequence of Event Recording setup digital inputs are used to determine the specific sequence of occurrence for recorded events. The signals identified in Requirement 1.2.6 are typically analog signals that vary over time in response to process conditions. We recommend either removing this requirement altogether or being much more specific as to what information should be collected and how.

Lastly, we disagree with the approach that NERC should be able to request information from an entity directly via a Reliability Standard requirement. Please note that we are not opposed to NERC requesting this information nor do we think it is inappropriate for NERC to receive said data. We do however disagree with the method of collection. It is our opinion that NERC should utilize the existing data collection mechanisms (i.e. Section 1600 data requests, NERC Alerts, etc.).

Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	

AES Clean Energy questions the reliability need for the proposed requirements at all IBRs because this goes beyond what is required at traditional synchronous plant facilities under current PRC-002. As stated in the Purpose statement, the intent of this Reliability Standard is to "have **adequate** data available from inverter-based resources (IBR) to facilitate analysis of Bulk Electric System (BES) Disturbances." This implies that the needs are not everywhere for data to assist in analyzing disturbance events. AES Clean Energy recommends the Standard Drafting Team consider adding requirement(s) for the Transmission Owner and/or Reliability Coordinator to develop a list of IBRs in their areas that require data based on a set of criteria similar to what is currently in PRC-002 and notify the affected GOs. Along with that, AES Clean Energy also recommends that Standard Drafting Team develop a set of criteria that can be used by the TO/RC to assess where disturbance monitoring equipment should be installed in their region. This set of criteria may include:

- Minimum MW/MVA threshold for IBRs requiring SER/FR/DDR
- Amount of IBRs connected in a particular area of the TO/RC region
- Level of grid strength of areas within the TO/RC region

There may be a need for a requirement for the TO/RC to assess periodically to determine a new list of IBRs, similar to PRC-002.

AES Clean Energy also urges the ERO to be considerate of the cost of installing these equipment while drafting the expecations of the standard and identify different options to ensure reliability of the interconnection. The above recommendations are to ensure that reliability is achieved through a reasonable cost approach.

Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
PRC-028-1 R1 sub-part 1.2.6 is not clear as to what control system values, reference values, and feedback signals need to be monitored.	
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 RSC	
Answer	
Document Name	
Comment	
NPCC RSC supports the drafting team proposal.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE has the following comments for PRC-028-1:	

- Texas RE recommends the drafting team define Inverter-based Resources (IBR) as it is being used increasingly in standard requirement language and a NERC Glossary definition would drive consistency. Footnote 2 may not be clear and it is inconsistent with the footnote description of IBR in proposed EOP-004-4.
- Texas RE recommends revising the PRC-028-1 Title to include all the applicable inverter-based systems such as STATCOM, SVC, HVDC, etc., other than the traditional inverter-based resources. Texas RE recommends the following verbiage: “Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources and Dynamic Devices”.
- Texas RE noticed that Section A 4.2.4 includes shunt static devices, but that device type does not appear anywhere in the requirement language. Texas RE inquires as to why this is included in section A 4.2.4
- The technical rational for PRC-028-1 states that SER data is required from all IBR units connected to last 10% of each collector feeder. Requirement 1.2, however, can be interpreted to needing the SER data from only one IBR unit from each feeder. Texas RE recommends making the requirement language consistent with the language in the technical rationale. In addition, SDT should consider providing clarification on the ‘installed date’ for the IBRs that are excluded from this requirement, whether this date is the date at which the IBR is installed in the field or the date at which the IBR is synchronized to grid or the date of commercial operation. Additionally, the requirement should state that the Generator Owner shall document the IBR recording limitations including OEM data sheet or other equipment specifications.
    - Texas RE recommends the following verbiage for Requirement Part 1.2: “All IBR units connected to last 10% of each collector feeder length. The Generator Owner shall document the IBR recording limitations and provide the information to its Reliability Coordinator, Regional Entity, or NERC, upon request. Evidence may include OEM data sheet or other equipment specifications.”
    - Texas RE recommends the technical rationale include the following: “IBR units with commercial operation date prior to the effective date of this standard and are not capable of recording this data are excluded.”
- Texas RE seeks clarity on the sub parts of Requirement Part 1.2 regarding what specifically needs to be recorded.
- Texas RE recommends the SDT clarify whether the data included in R2.1.3 and R2.3.3 can be calculated values or not. Texas RE recommends the following verbiage for Requirement Part 2.1.3: “Three phase Real and Reactive Power (measured or calculated)”
- Requirement Part R2.2 states that IBR unit FR data is needed; however, the sub-requirements state the data can be from the unit terminals or on high-side of the IBR unit transformer. If more than one IBR units are connected to a transformer, then IBR unit level data will not be available based on the current language.
    - Texas RE recommends the language for R2 be changed to "…as applicable, at IBR unit terminals or on high-side of the IBR unit transformer if no more than one IBR is connected to a unit transformer."
- Texas RE requests the sub requirements not include the Regional Entity and NERC. Regional Entities and NERC may request data from registered entities in accordance with section 1600 of the Rules of Procedure.
- Since PRC-028 is intended to have a similar purpose as PRC-002, but specific to IBRs, Texas RE recommends PRC-028 Requirement R7 should mirror PRC-002 Requirement R11. Texas RE inquires as to why IBRs can retrieve data for 30 days while conventional units only have 10 days to retrieve data.
- Texas RE also inquires as to why the synchronized clock accuracy in PRC-028 Requirement R6 is plus/minus 100 milliseconds of UTC, but in PRC-002 Requirement R10, it is plus/minus 2 milliseconds.
- Additionally, Texas RE noticed the PRC-002 Requirement R9 output 30 times per second versus PRC-028 Requirement R5 output is 60 times per second.
- Texas RE requests the SDT update Section C Compliance to the most updated version. For example, Compliance Violation Investigations listed in section C 1.3 do not exist.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	

Document Name	
Comment	

Minnesota Power's comments are aligned with the MRO NSRF & EEI comments.

Likes 0	
Dislikes 0	
Response	

Bret Galbraith - Seminole Electric Cooperative, Inc. - 6

Answer	
Document Name	
Comment	

1. In the draft Standard PRC-028, Requirement R1.2, a value of 10% is employed. Reviewing significant digits, it's unclear whether this is 10% or 10.0%, etc. Can the NERC STD provide additional guidance?

2. Some IBR units may be procured prior to the enforcement date of the Standard. Due to supply chain issues, PRC-028 R1.2 should be modified to allow an exemption for sites "procured" prior to the FERC approval of this Standard.

3. PRC-028 R1.2 states "and are not capable of recording this data are excluded". Can the SDT provide examples of situations where an IBR is "not capable" of recording this data. This will help provide a basis for discussion with auditors who may assert that "capable" is a vague term, which may lead to unintended disagreements between a utility and audit staff.

4. It's unclear whether NERC intends to modify PRC-028 if traditional non-BES IBR are added to NERC Standards pursuant to parallel analysis ongoing at NERC. Can the NERC SDT comment on how it will deal with IBR that connects at less than 100 kV or is less than 75 MVA, etc., i.e., non-traditional BES sources?

Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	
Comment	

The NAGF notes that PRC-002 uses a methodology/threshold for selecting BES buses that require Sequence of Events Recording (SER) and Fault Recording (FR) Data. The NAGF recommends that the Standard Drafting Team consider a similar approach for PRC-028, requiring the TO and RC to *identify areas within their regions that are susceptible to disturbances (or high concentration of IBRs) that would benefit from monitoring and recording capabilities. This would mitigate the financial impact to the industry as a whole, and target the investment on the areas that need it most.*

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	

Comment

See comments submitted by the Edison Electrical Institute

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI Comments on PRC-028-1:

Purpose Statement: EEI does not agree that the purpose statement for this Reliability Standard aligns with the intended scope of this project. To address this concern, we offer the following edits in boldface:

To have adequate data available from **a representative number of** inverter-based resources (IBR)**/Facilities** to facilitate **the** analysis **of IBR performance during** Bulk Electric System (BES) Disturbances.

Functional Entities: EEI does not agree with the Functional Entities as listed. We believe that PRC-028 should also include Reliability Coordinators (RC) in this list, noting that the SAR was never intended to require monitoring of IBRs at all locations. Instead, the SDT should develop a criteria for identifying where and when monitoring should be installed and the RC should be the entity that 1) utilizes that criteria to determine where monitoring is needed and 2) notifies owners of their obligations.

Applicability Section: EEI does not agree with the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in the BES Definition, Inclusion I2. (See EEI comments for Question 1)

All Requirements: EEI does not agree that this project was intended to monitor all IBRs or IBR Facilities. The SAR states that the intent is to install DDR at some locations, not all locations. The SAR also stated that the requirements were to be balanced against costs which given the magnitude of the proposed requirements, it is difficult to see where costs were adequately balanced.

EEI recommends the SDT develop a criteria that can be used by RCs in assessing where disturbance monitoring should be installed to ensure BES performance is effectively analyzed during disturbances, particularly in areas of high IBR penetration.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	
Document Name	

Comment

RE: Section C. Compliance: PRC-002-5 and PRC-028-1: Please consider updating section "1.3 Compliance Monitoring and Enforcement Program" with the most recent NERC wording for this section. Please consider removing section "1.4 Additional Compliance Information - None."

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation does not have any additional comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment	
OPG supports the NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	
Document Name	

Comment

The requirement to install recording devices to capture IBR performance data through PRC-028-1 should align as closely as possible with the implementation timeframe for the changes made to EOP-004 in Project No. 2023-01 (EOP-004 IBR Event Reporting). This will help ensure that the Events Analysis process has all pertinent data available to make more thorough assessments of IBR-related events.

The SRC believes that referencing just Part (b) of Inclusion I2 in Section 4.2 of the Applicability section of PRC-028-1 is unnecessary, as the language already limits applicability to IBRs and it would be inappropriate to exclude any individual IBRs with a gross individual nameplate rating greater than 20 MVA from the applicability of the standard. The SRC therefore recommends that Section 4.2 of the Applicability section of PRC-028-1 be modified as follows: "The following Elements associated with the inverter-based portion of generating plants/Facilities meeting the criteria set by Inclusion I2 or Inclusion I4 of the BES definition." The SRC has proposed a corresponding modification to the Applicability section of PRC-002-5 in its response to question 1, above. The SRC also recommends that the Applicability section of both standards be aligned with the IBR registration criteria that NERC is in the process of developing under FERC proceeding RD22-4-001.

Based on its review of the draft standards, the SRC is concerned that it is unlikely that transmission system buses in areas of high IBR penetration will be required to have disturbance monitoring and the SRC notes that this monitoring is critical to determining IBR performance on the power system. The Applicability of PRC-028-1 is limited to IBR Facilities, and the methodology in PRC-002-5 Attachment 1 appears to focus on identifying buses with higher fault current levels, which are unlikely to be located in areas with high IBR penetration. The SRC requests that the SDT confirm whether this is the intent of the standards and revise the standards appropriately if this is not the intent.

The SRC notes that PRC-028-1, Requirement 3, Parts 3.1.3, 3.2.3, and 3.3.3 require various forms of trigger settings but do not define associated trigger thresholds. The SRC is concerned that the absence of trigger thresholds will result in inadequate data collection and recommends that the standard be revised to establish default trigger thresholds that apply unless otherwise agreed by the Reliability Coordinator. One possible default threshold would be a requirement that data be captured whenever an IBR changes modes.

Regarding Requirement R7, Part 7.2, the SRC is concerned that allowing 30 calendar days for data to be provided will result in an unacceptably risky delay in the event analysis process. To address this issue, the SRC recommends that Part 7.2 be revised to require that data be provided as soon as possible, but no later than 7 calendar days after a request. PMUs can provide the same data and data storage capabilities this standard requires from

DDRs while also providing real-time reporting capability. We ask the project team to affirm PMUs as a means to provide the required data. If so, the performance requirements should not limit any viable option.

The SRC is concerned that Requirement R8 is inadequate to ensure availability of critical data. To address this issue, the SRC recommends that R8 be revised to require regular testing and maintenance of recording equipment and associated infrastructure or to provide that a failure to provide requested data is a violation of PRC-028-1 regardless of the cause of the failure to provide data.

Finally, the SRC recommends that the following revisions be made to PRC-028-1 to more closely align it with table 19 of IEEE 2800:

- Revise Requirement R2, Part 2.1 to require the following additional data points:

o Bus frequency,

o Calculated active and reactive power output, and

o Applicable binary status (e.g., relay out codes).

- Revise Requirement R2, Part 2.2 to require the following additional data points at the plant level:

o Bus frequency,

o Calculated active and reactive power output, and

o Applicable binary status (e.g., relay out codes).

- Revise Requirement R2, Part 2.3 to require bus frequency as an additional data point.

- Revise the total record length in Requirement R3, Parts 3.1.1, 3.2.1, and 3.3.1 from 2 seconds to 5 seconds.

- Revise Requirement R4, Part 4.2 to require the phase current AND the positive sequence current instead of only requiring one or the other.

- Revise Requirement R6, Part 6.2 to require data synchronization accuracy to 1 microsecond at the plant level and 100 microseconds at the unit level.

- Revise the data retention periods in Requirement R7, Part 7.1 to 90 days for SER and FR data and 1 year for DDR data.

- Align the SER data format in Attachment 1 with the format used in IEEE 2800 table 19 and with PRC-002 Attachment 2 by revising it to read as follows:

o Date, Time, Local Time Code, Plant Substation, Device, State, Event type (status changes, synchronization status, configuration change, etc.), Sequence number (for potential overwriting).

o The SRC notes that some breakers may be owned by the generator owner at the station beyond the first station.

- Revise Requirement R7, Part 7.4 to include a reference to IEEE revision C37.111-2013 or later.

Likes 0	

Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	
Document Name	

Comment

PNMR is in support of EEI's commnents for question 5.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation does not have any additional comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	

Dislikes 0	
Response	

Israel Perez (Proxy for Thomas Johnson) – Salt River Project

Questions:

1. Yes
2. Yes
3. No

   PRC-028 -The data sampling rates seem excessive and are a significant increase from the requirements in PRC-002. These sampling rates will prevent the use of protective relaying to satisfy the standard, which will increase cost burden

4. Yes
5. Additional Comments

   PRC-028 - If the point of 4.2.5 is to monitor the individual inverter performance prior to being summed into a collector system, I would consider mandating the last IBR on each feeder is monitored, rather than one of the IBR units in the last 10% of each feeder.

Consideration of Comments

Project Name:	2021-04 Modifications to PRC-002 – Phase II | Draft 1
Comment Period Start Date:	8/1/2023
Comment Period End Date:	9/14/2023
Associated Ballot(s):	2021-04 Modifications to PRC-002 – Phase II Implementation Plan IN 1 OT 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 | Non-Binding Poll IN 1 NB 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 IN 1 ST 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll IN 1 NB 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 IN 1 ST

There were 71 sets of responses, including comments from approximately 182 different people from approximately 121 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, Soo Jin Kim (via email) or at (404) 446-9742.

Questions

1. **Do you agree with the modification in "Applicability, Section 4.2. Facilities" in PRC-002-5?**

2. **Do you agree with the need of creating a new Standard (PRC-028-1) to address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002?**

3. **Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?**

4. **Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?**

5. **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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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	MRO,SPP RE,WECC	SRC 2023	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

					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC

					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	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
					Scott Brame	North Carolina Electric Membership Corporation	1,3,4,5	SERC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Andy Fuhrman	Minnkota Power Cooperative, Inc.	1	MRO
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Andrew Anderson	Wolverine Power Supply Cooperative, Inc.	1	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC

					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO

					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO

					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
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
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
					Frank Lee	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
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC

					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	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
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated	1	NPCC

						Edison Co. of New York		
					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
					Joshua London	Eversource Energy	1	NPCC
Stephen Whaite	Stephen Whaite			ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	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	3	SERC

						Electric Power Cooperative		
					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 with the modification in "Applicability, Section 4.2. Facilities" in PRC-002-5?	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Do not agree with modification. Modification implies that inverter-based resources are to be included in the BES definition Inclusion I2. This interpretation doesn't conform with the current version of the BES definition.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The Inclusion I2 of the BES definition is removed from the Applicability Section.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
At some utilities we record wicket gate opening % by recording the 4-2 mA gate position in series with plant instrumentation.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The submitted comment is not applicable to standards addressed by this SDT.	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Please clarify that the requirements for reporting only pertain to entities covered by the NERC standard. This can be accomplished by deleting footnote 1 and replacing the phrase "IBR generation loss" with "GO-IBR".	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The reliability standard PRC-028 applies to facilities meeting the Inclusion I4 of the BES definition. As such, those Facilities are excluded from the Reliability Standard PRC-002. As directed by recent FERC Orders (Order No. 901 and IBR Registration Order), the standard would also apply to Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. Refer to technical rationale for more details.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Talen supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Please see response to the NAGF comments.

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Do not agree with modification. Modification implies that inverter-based resources are to be included in the BES definition Inclusion I2. This interpretation doesn't conform with the current version of the BES definition.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The Inclusion I2 of the BES definition is removed from the Applicability Section.	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's comments which state: EEI does not agree with the modifications to the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in BES Definition, Inclusion I2. This interpretation does not conform to the approved version of the Bulk Electric System Reference Document, Version 3, dated August 2018. If NERC believes that this interpretation is no longer appropriate, or otherwise invalid, they should work with the industry to modify the BES definition and associated support documents. EEI further notes that this project was not approved to Add, Modify or Retire a Glossary Term.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The Inclusion I2 of the BES definition is removed from the Applicability Section.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation recommends that section 4.2 be removed as justification for limiting the inclusions from the BES Definition in the glossary of terms is not provided, limiting the scope of Disturbance Reporting.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Your concern is noted. Please refer to technical rationale documents for PRC-002 and PRC-028.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Please see response to NAGF's comments.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to NAGF's comments.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to NAGF's comments.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No

Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to NAGF's comments.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see responses to other comments.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports other opposing comments that have been submitted.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see responses to other comments.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see responses to other comments.	
Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. See response to EEI's comment.

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of their members:

EEI does not agree with the modifications to the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in BES Definition, Inclusion I2. This interpretation does not conform to the approved version of the Bulk Electric System Reference Document, Version 3, dated August 2018. If the interpretation is no longer appropriate, or otherwise invalid, the BES definition and associated support documents should be revised. EEI further notes that this project was not approved to Add, Modify or Retire a Glossary Term.

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The Inclusion I2 of the BES definition is removed from the Applicability Section.	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	
Comment	

SMUD and BANC support the comments submitted by EEI.

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	
Comment	
PG&E supports the input provided by the NAGF related to cost and EEI related to the implied inclusion of Inverter-Based Resources (IBR) as part of the BES Definition.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to NAGF and EEI comments.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. See response to EEI's comment.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	

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	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not agree with the modifications to the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in BES Definition, Inclusion I2. This interpretation does not conform to the approved version of the Bulk Electric System Reference Document, Version 3, dated August 2018. If the interpretation is no longer appropriate, or otherwise invalid, the BES definition and associated support documents should be revised. EEI further notes that this project was not approved to Add, Modify or Retire a Glossary Term.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comments. The Inclusion I2 of the BES definition is removed from the Applicability Section.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
The BES Reference Document, Version 3, August 2018, verbiage and clarifying illustrations indicate that I4 was created for IBRs, and that IBRs are included within scope only by I4 and not I2. Suggest either removing references to I2 in the proposed Applicability Section 4.2, or stating without specific inclusions, e.g., "... excluding inverter-based portions of generating plants/Facilities included in the BES by meeting the BES definition." Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The Inclusion I2 of the BES definition is removed from the Applicability Section.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	
The SRC agrees with the modification in Section 4.2 of the Applicability section in PRC-002-5; however, consistent with the recommended modification to the Applicability section of PRC-028-1 detailed in the SRC’s response to question 5 below, the SRC recommends that Section 4.2 of the PRC-002-5 Applicability section be revised to refer to the entirety of Inclusion I2 instead of only referring to I2, Part (b).	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Considering other received comments, the Inclusion I2 of the BES definition is removed from the Applicability Section.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR is in support of the EEI comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) for this question and adopts them as its own.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. See response to IRC SRC's comment.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
The BES Reference Document, Version 3, August 2018, verbiage and clarifying illustrations indicate that I4 was created for IBRs, and that IBRs are included within scope only by I4 and not I2. Suggest either removing references to I2 in the proposed Applicability Section 4.2, or stating without specific inclusions, e.g., "... excluding inverter-based portions of generating plants/Facilities included in the BES by meeting the BES definition." Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The Inclusion I2 of the BES definition is removed from the Applicability Section.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thanks for taking time to review proposed revisions to reliability standard PRC-002 and new reliability standard PRC-028.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thanks 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	
The changes make it clear that PRC-002 does not apply to IBR facilities.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The changes make it clear that PRC-002 does not apply to IBR facilities. The MRO NSRF would like to note the word "portions" in Applicability Section 4.2 may add confusion, consider if it can be removed or if other wording can be used.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Considering other received comments, the Inclusion I2 of the BES definition is removed from the Applicability Section. As a result, work "portions" is no longer used in the Applicability Section 4.2.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees with the modification and understands the intent of the Standard Drafting Team (SDT); however, SIGE encourages the SDT to clarify the effects of the proposed changes to the NERC Glossary Definition and BES Reference Document.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support. The Inclusion I2 of the BES definition is removed from the Applicability Section.	

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	Yes
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comments.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	

Comment	
The changes make it clear that PRC-002 does not apply to IBR facilities.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports the NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks 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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	
Thanks for your support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	

Thanks for your support.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ruida Shu - Northeast Power Coordinating Council - 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	
Thanks for your support.	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Michiko Sell - Pine Gate Renewables - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	

Response
Thanks for your support.

2. Do you agree with the need of creating a new Standard (PRC-028-1) to address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002?

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR supports EEI's comment related to not being in agreement of installing disturbance monitoring equipment at all IBR locations that conform to the BES definition is necessary, nor do we agree that the SAR authorized such an expansive scope.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF supports creating the new Standard PRC-028 focused on inverter-based resource disturbance monitoring and reporting requirements, but does not agree that all IBR facilities need DME at the substation and on each feeder circuit. Please consider the effectiveness of the application of DME only at the substation/collector bus for IBR facilities rather than on each feeder, and of limiting the facilities to which the addition of DME is required as determined by the process outlined in Question 5 below. *There is already some ability, without the addition of DME at all IBR locations, to determine the causes of inverter reactions to HV system disturbances as demonstrated in the various disturbance reports which list the various type of responses that have been published.*	
Likes 0	
Dislikes 0	
Response	
Thanks for supporting creation of the new Reliability Standard PRC-028. The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs. However, the SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	No
Document Name	

Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comment.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The long list of possible causes of the reactions found in the multiple disturbance reports from the past 5 years indicate that sufficient data is already available to determine what is occurring at the inverter level. From the multiple disturbance evaluation reports that have been written in the past 5 years, it appears that the reaction of the inverters to system disturbances has become well understood. It is not apparent that every IBR plant will needs to have the added ability to evaluate the required data collected by the newly required monitoring specified. PRC-002-4 recognized that certain facilities are more significant to the reliability of the BES as indicated by the TO evaluation and TP evaluation included in Requirement R1 and R5 of that version. Extending this standard's requirements to all IBR facilities seems to be a bit of an over-reaction.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Thanks for your comments. Recent NERC disturbance reports have identified that plant-level high resolution oscillography data and unit level sequence of events recording, and oscillography data are not available in most cases for event analysis. The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. See responses to other opposing comments.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See responses to other opposing comments.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See responses to other opposing comments.	
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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	

Answer	No
Document Name	
Comment	
Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to MRO NSRF's comment.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The implementation timeframe should be 24 months or the NERC GO-IBR registration deadlines, whichever is greater.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard applies to facilities meeting the Inclusion I4 of the BES definition. As directed by recent FERC Orders (Order No. 901 and IBR Registration Order), the standard also applies to Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. Refer to technical rationale for more details.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the proposed reliability standard PRC-028. Many changes have been made considering received comments with a first posting.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation recommends that the Standard Drafting Team consider a similar approach for PRC-028 as in PRC-002, requiring the TO and RC to identify areas within their regions that are susceptible to disturbances (or high concentration of IBRs) that would benefit from monitoring and recording capabilities. As opposed to a blanket requirement for ALL IRB facilities to install SER, FR, and DDR equipment. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Recent NERC disturbance reports have identified that plant-level high resolution oscillography data and unit level sequence of events recording, and oscillography data are not available in most cases for event analysis. The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their	

buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports the NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NPCC RSC's comments.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation recommends that the Standard Drafting Team consider a similar approach for PRC-028 as in PRC-002, requiring the TO and RC to identify areas within their regions that are susceptible to disturbances (or high concentration of IBRs) that would benefit from monitoring and recording capabilities. As opposed to a blanket requirement for ALL IRB facilities to install SER, FR, and DDR equipment. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the development of a new Reliability Standard to address gaps in disturbance monitoring of IBRs, however, we do not agree that installing disturbance monitoring equipment at all IBR locations that conform to the BES definition is necessary, nor do we agree that the SAR authorized such an expansive scope.	
Likes 0	
Dislikes 0	
Response	
Thanks for supporting development of a new Reliability Standard to address gaps in disturbance monitoring of IBRs. The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	
Ruchi Shah - AES - AES Corporation - 5	

Answer	Yes
Document Name	
Comment	
AES Clean Energy supports the creation of PRC-028 to address gaps identified by the IRPTF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thanks 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 for question #2.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to EEI's comment.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to EEI's comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to EEI's comment.	
Michael Johnson - Michael Johnson On Behalf of: 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 supports the SDT decision to separate the Inverter-Based Resource requirements to avoid making PRC-002 overly complicated by trying to address both synchronous and IBRs in a single standard.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	Yes
Document Name	
Comment	
Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to EEI's comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
The long list of possible causes of the reactions found in the multiple disturbance reports from the past 5 years indicate that sufficient data is already available to determine what is occurring at the inverter level. From the multiple disturbance evaluation reports that have been written in the past 5 years, it appears that the reaction of the inverters to system disturbances has become well understood. It is not apparent that every IBR plant needs to have the added ability to evaluate the required data collected by the newly required monitoring. PRC-002-4 recognized that certain facilities are more significant to the reliability of the BES as indicated by the TO evaluation and TP evaluation included in Requirement R1 and R5 of that version. Extending this standard's requirements to ALL IBR facilities seems to be a bit of an over-reaction.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Recent NERC disturbance reports have identified that plant-level high resolution oscillography data and unit level sequence of events recording, and oscillography data are not available in most cases for event analysis. The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to NAGF’s comments.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	

Black Hills Corporation agrees with NAGF comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to NAGF's comments.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to NAGF's comments.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comments. See response to NAGF's comments.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy supports EEI's comments which state: EEI supports the development of a new Reliability Standard to address gaps in disturbance monitoring of IBRs, however, we do not agree that installing disturbance monitoring equipment at all IBR locations that conform to the BES definition is necessary, nor do we agree that the SAR authorized such an expansive scope.	
Likes 0	
Dislikes 0	
Response	
Thanks for supporting development of a new Reliability Standard to address gaps in disturbance monitoring of IBRs. The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
PRC-028 to include requirements for adequate monitoring of IBRs as shown necessary by operational experience. PRC-002 to remain in effect for synchronous based generation for a large-scale view of system reliability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

PRC-028 to include requirements for adequate monitoring of IBRs as shown necessary by operational experience. PRC-002 to remain in effect for synchronous based generation for a large-scale view of system reliability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
PRC-028 to include requirements for adequate monitoring of IBRs as shown necessary by operational experience. PRC-002 to remain in effect for synchronous based generation for a large-scale view of system reliability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

While AEP has no objections to creating a new standard specifically for IBRs, we are concerned by the content itself which we express in our response to Question 5.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF	
Answer	Yes
Document Name	
Comment	
To the extent of monitoring only those IBRs that are connected directly to the BES.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support. The standard would apply to resources applicable to Inclusion I4 of the BES definition only. As directed by recent FERC Orders (Order No. 901 and IBR Registration Order), the standard would also apply to Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. Refer to technical rationale for more details.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Michiko Sell - Pine Gate Renewables - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ruida Shu - Northeast Power Coordinating Council - 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	
Thanks for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	
Thanks for your support.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	
Thanks for your support.	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks 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	
Thanks for your support.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan	
Answer	
Document Name	
Comment	
Not applicable	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.

3. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?	
Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF	
Answer	No
Document Name	
Comment	
I agree that PRC-002 -5 changes are cost effective. The new PRC-028-1 standard will increase costs significantly for those utilities that have installed IBRs prior to the standards effective date.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
The following unnecessary equipment requirements will lead to increased project cost.	

Section 2.2

2.1 PRC-002 does not require real and reactive power for FR data, the same should apply for PRC-028

2.2 There is limited value with FR data for IBRs and this requirement should be removed.

2.3 There is limited value with FR data for shunt or reactive devices and this requirement should be removed.

-This section should also exclude IBRs that were installed prior to the approved standard. Only DDR or continuous data should be required on IBRs that were installed prior approval.

Section 3 - The sample rate and record length requirements are not consistent with the requirements in PRC-002. The 128 samples per cycle recording rate and 2 second record length may not be supported by installed or available technology, especially for IBRs. Note- Vistra has been evaluating various technologies that we could use for IBRs and there are not many cost effective options for IBRs.

Section 5 The output sampling rated of 60 times per second is not consistent with the 30 times per second requirement in PRC-002

Section 7 The time period for storing events is 30 days vs the 10 days in PRC-002. Not all equipment can store DDR or continuous data for 30 days.

Likes 0	
Dislikes 0	

Response

Thanks for your comments.

The real and reactive power can be calculated using recorded voltages and currents, which is allowed. In PRC-028, the FR data is focused on IBR generating facilities and real/reactive power data will be useful for event analysis.

The FR data from IBR generating facility, including response from any dynamic reactive device, will be helpful in evaluating performance of IBR during a system a disturbance.

Recent NERC disturbance reports have identified that plant-level high resolution oscillography data and unit level sequence of events recording, and oscillography data are not available in most cases for event analysis.

Considering all received comments, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

It has been recognized in past Technical Rationale documents for PRC-002, by members of their SDT, that requiring more than 10 days of granular data retention would be expensive and unnecessary. Requiring 30 days of data retention and provision would obviously be even more expensive than ten, making the proposed revisions unreasonable and not “cost effective.”

In addition, AEP has several other concerns with the cost impact of the new Standard PRC-028-1.

* AEP does not consider the inclusion of “at least one IBR unit connected to last 10% of each collector feeder length” in PRC-028 4.2.5 as cost effective. AEP questions the reliability benefit data these BES Elements will provide when considering the proposed changes to PRC-024 to a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances and the requirements of PRC-004, Protection System Misoperation and Correction.

* PRC-028 does not currently limit the applicability of required data, while PRC-002 provides criteria which limits the BES Elements that are required to have dynamic Disturbance recording data. Similar limitations should be placed on PRC-028 as well.

* PRC-004 excludes Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities. PRC-028 should be developed in alignment with PRC-004 by retaining these exclusions in PRC-028 in its present state, as well as in its future state.

Likes 0	

Dislikes 0	
Response	
Thank you for your comments.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Cost effectiveness cannot be known at this time.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

The modifications made to PRC-002 are a zero-cost item. The costs associated with PRC-028 are substantial. Some IBR facilities have a single feeder into the 34.5kv collector bus while other sites may have 12 or more feeder circuits. Requiring monitoring on each feeder is excessive. Requiring monitoring on wind facilities is not warranted as most of the disturbance events that have been studied have revealed that solar facilities are the most susceptible to reacting to system disturbances.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of “each” collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days. The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Talen supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Cost effectiveness cannot be known at this time.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	

Comment	
Until FE understands the definition intent of inverter-based resources under these standards, we cannot determine the cost effectiveness of this project. In addition, FE supports EEI's comments which state: EEI is concerned that proposed PRC-028-1 does not align with the approved SAR scope and if approved would place unreasonable costs on registered entities without adequately balancing costs as required by the SAR. We further note that the SAR Scope states that "it is important that some of these resources and nearby BES elements are monitored with DDR devices to ensure adequate coverage for disturbance analysis while balancing cost impacts." The SAR does not intend that all IBR facilities need to have the level of monitoring proposed. To address this concern, the SDT should develop criteria that allows entities to select a representative number of sites in order to ensure adequate analysis of IBR performance.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro thanks the drafting team for their efforts and appreciates the opportunity to comment. PRC-028-1 Requirements are generally more stringent than PRC-002 requirements, particularly, fault recording (FR) sampling, FR triggering, FR length, CLK accuracy, and retrieval period requirements. Entities will have to assess if current PRC-002 monitoring solutions are capable of	

meeting technical requirements in PRC-028-1 as currently drafted, and may have to develop new monitoring systems if currently implemented solutions are unable to meet the increased requirements.

While the technical justification cites IEEE 2800-2022 as a basis for the requirements, it does not appear to identify instances where Disturbance Monitoring Equipment records meeting PRC-002 requirements would have been insufficient for event or disturbance analysis, which could justify increased technical requirements in PRC-028-1 Draft 1.

Requirement R3 asks for more data and it applies to all in scope IBR facilities, regardless of installation date whereas R1 and R2 have specific exemption criteria for existing units. Requirements R4, R5 specify DDR requirements similar to PRC-002; however as drafted these Requirements will be applicable to all in scope IBR facilities unlike Requirements R1 and R2.

BC Hydro suggests that technical requirements for PRC-028 be specified in line with PRC-002 requirements for IBRs installed prior to the effective date of the standard. This will still constitute an improvement over the status quo for availability and quality of records, while improving cost effectiveness of the proposed changes in PRC-028.

PRC-028-1 Requirements R1 and R2 provide an exemption to IBR units “installed” prior to the effective date of the Standard. Please provide clarity on the meaning of the term “install”.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Considering comments received with the initial posting, many revisions are made. The Requirements in PRC-028 are different from same in PRC-002, recognizing that IBRs react very fast to system disturbances and advances in recording technology.

Exception in Requirement R1 is for IBR units placed in commercial operation before the effective date of the standard. There is no need for such an exception in R3 and R4 as these requirements are for FR and DDR data for the IBR plant.

The term “installed” is replaced with “commercial operation.”

Wendy Kalidass - U.S. Bureau of Reclamation - 5

Answer	No

Document Name	
Comment	
Reclamation agrees with the PRC-002-5 cost but inverter base does not apply to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	

Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments: It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement. As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we strongly disagree with making this new standard inclusive of all IBR facilities regardless of risk to the BES. It is our recommendation that PRC-028 take a similar approach as PRC-002-5 and allow the TO and RC to evaluate which IBR Facilities need SER, FR, and/or DDR capabilities installed. It is our opinion that a blanket approach is cost-prohibitive whereas a risk-based approach provides a reasonable level of information and is much more cost-effective.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. Additionally, the recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for	

analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support. See response to MRO NSRF's comments.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	

NO. The proposals will result in more time and $$ spent on unproductive activities. SDTs should be required to provide cost/benefit analysis and prove the reliability benefits of their proposals.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Recent NERC disturbance reports have identified that plant-level high resolution oscillography data and unit level sequence of events recording, and oscillography data are not available in most cases for event analysis. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of “each” collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
The proposals will result in more time and $$ spent on unproductive activities. SDTs should be required to provide cost/benefit analysis and prove the reliability benefits of their proposals. NO, NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Recent NERC disturbance reports have identified that plant-level high resolution oscillography data and unit level sequence of events recording, and oscillography data are not available in most cases for event analysis. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data	

from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
The proposals will result in more time and $$ spent on unproductive activities. SDTs should be required to provide cost/benefit analysis and prove the reliability benefits of their proposals.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Recent NERC disturbance reports have identified that plant-level high resolution oscillography data and unit level sequence of events recording, and oscillography data are not available in most cases for event analysis. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	

The proposals will result in more time and $$ spent on unproductive activities. SDTs should be required to provide cost/benefit analysis and prove the reliability benefits of their proposals. NCPA supports other opposing comments that have been submitted.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Recent NERC disturbance reports have identified that plant-level high resolution oscillography data and unit level sequence of events recording, and oscillography data are not available in most cases for event analysis. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of “each” collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	No
Document Name	

Comment

PRC-028 -The data sampling rates seem excessive and are a significant increase from the requirements in PRC-002. These sampling rates will prevent the use of protective relaying to satisfy the standard, which will increase cost burden.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The IBRs are fast acting devices and hence, high sampling rate compared to one specified in PRC-002 is required. However, considering comments submitted by the industry, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The modifications made to PRC-002 are a zero-cost item. The costs associated with PRC-028 are substantial. Some IBR facilities have a single feeder into the 34.5kv collector bus while other sites may have 12 or more feeder circuits. Requiring monitoring on each feeder is excessive. Requiring monitoring on wind facilities is not warranted as most of the disturbance events that have been studied have revealed that solar facilities are the most susceptible to reacting to system disturbances.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	

Comment	
The modifications made to PRC-002 are a zero-cost item. The costs associated with PRC-028 are substantial. Some IBR facilities have a single feeder into the 34.5kv collector bus while other sites may have 12 or more feeder circuits. Requiring monitoring on each feeder is excessive. It is estimated that it will cost $300-450k to install DFR equipment on each collection system feeder; with an aggregate cost of $4.2-$6.4 million just for that wind generation asset with at least 14 collection system feeder circuits. The MRO NSRF recommends limiting applicability to only facilities that have experienced reportable events where clear causes have not been identified and limiting the monitoring location to the BES collection bus. Another costly part depends on how exclusions are handled for older less capable equipment in PRC-028-1 R1, R2 and R3. Requiring monitoring on wind facilities is not warranted as most of the disturbance events that have been studied have revealed that photo-voltaic facilities are the most susceptible to reacting to system disturbances.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Thanks for your comment. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	No
Document Name	
Comment	

Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to EEI’s comments.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
The SAR Scope states that “it is important that **some of these resources and nearby BES elements are monitored with DDR devices** to ensure adequate coverage for disturbance analysis while balancing cost impacts.” However, the SAR does not intend that all IBR facilities need to have the level of monitoring proposed. To address this concern, the SDT should develop criteria that allows entities to select a representative number of sites in order to ensure adequate analysis of IBR performance. Requiring monitoring at all IBR facilities would result in unnecessary costs without improving reliability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. Additionally, the recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to NAGF's comments.	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC believe that the new Standard PRC-028-1 is not cost effective and we support the comments submitted by Southern Company.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to Southern Company's comments.	

Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	
Comment	
PG&E supports the input provided by the NAGF and EEI on the potential costs of the proposed modifications.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to NAGF and EEI's comments.	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response MRO NSRF's comments.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	No

Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	

Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
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	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #3. In addition, Evergy estimates that the cost of installing DFR equipment on the high side of a pad mounted transformer at the base of a wind turbine in the last 10% of an existing wind turbine feeder will be $300-450k or 2-3 times the cost of installing the same equipment in an existing substation. For example, one wind farm has 14 feeders so installing this equipment on every feeder there would cost an estimated $4.2-6.3 million dollars for that one facility. EIA data shows that there are currently 604 wind farms with a size of 75 MW or greater with a total 975549 MW capacity. Assuming there is a feeder for every 10-20 MW worth of wind turbines and the estimate per installation, the range between $1.463-$2.195 billion dollars just to install these at the end of every feeder and does not include the substation installations that would be required. This estimate is only for feeders at wind turbines and does not include any estimates for solar farms or other IBRs so the total cost could likely be double or triple this estimate. This expense has minimal or no direct benefit to grid reliability and will increase electricity costs for everyone across North America in a quest for better data. Evergy highly suggests that the drafting team consider limiting the scope of DFR installations to areas that are identified by an RC similar to what is done in PRC-002.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comments. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of “each” collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
It is ACES’ opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement. As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we strongly disagree with making this new standard inclusive of all IBR facilities regardless of risk to the BES. It is our recommendation that PRC-028 take a similar approach as PRC-002-5 and allow the TO and RC to evaluate which IBR Facilities need SER, FR, and/or DDR capabilities installed. It is our opinion that a blanket approach is cost-prohibitive whereas a risk-based approach provides a reasonable level of information and is much more cost-effective.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments.	

The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. Additionally, the recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.

The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of “each” collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

We recommended the drafting team consider the establishment of a minimum MW threshold to ensure very small installations, such as those that may be considered BES due to co-location with synchronous machines, are excluded to ensure cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Considering all comments received, the IBR-portion of generating facility meeting Inclusion I2 of the BES definition is removed from the Applicability Section.

Ruchi Shah - AES - AES Corporation - 5

Answer	No

Document Name	
Comment	

There should not be any cost associated with the modifications made in PRC-002-5. However, costs associated with PRC-028-1 are substantial. Depending on the configuration and equipment capability of existing operational IBR facilities, the costs associated with retrofitting hardware, software and labor will run into 6 figure amount for a single IBR site.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of “each” collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	
Comment	

The PRC-002-5 changes are cost effective.

PRC-028-1 is not cost effective and should align more with the requirements of PRC-002. Specifically, PRC-028 should be consistent with the PRC-002 data retrievability period of 10 calendar days instead of 30 calendar days (PRC-028 R7.1) especially for DDR data. PRC-028 should also let the TO and RC evaluate (as was done in PRC-002) which IBR Facilities need SER, FR, and/or DDR capabilities installed, instead of including all IBR facilities regardless of risk to the BES. PRC-028 should also follow PRC-002 FR requirements which do not require real and reactive power for FR data (PRC-028 R2.1.3) and have a minimum sample rate of 16 samples per cycle instead of 128 samples per cycle (PRC-

028 R3.2.2). PRC-028 should also be consistent with PRC-002 DDR requirements for an output recording rate of electrical quantities of at least 30 times per second instead of 60 times per second (PRC-028 R5.2).	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of “each” collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	No
Document Name	
Comment	
It will be costly to implement.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of “each” collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for	

FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power's comments are aligned with those of the MRO NSRF and EEI for this question. Minnesota Power reiterates that PRC-028 would result in substantial costs for entities and disagrees with the proposal to monitor all IBR facilities.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment.

The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. Additionally, the recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.

The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.

Michiko Sell - Pine Gate Renewables - 5	
Answer	No
Document Name	
Comment	

We are concerned that the cost and burden of the proposed PRC-028 requirements are not justified by the reliability benefits it would provide. We believe the costs and benefits of the proposed standard can be better balanced by a. only requiring data collection at generating plants larger than 500 MVA, b. requiring data collection on a single collector feeder or IBR unit instead of every collector feeder or IBR unit in the plant, and c. only applying the data collection requirements to plants that sign an interconnection agreement after the effective date of the standard. Only applying the requirements to a single IBR unit and to larger plants will make PRC-028 more comparable to the PRC-002 companion standard for synchronous generators, avoiding undue discrimination against Inverter-Based Resources (IBRs).

Regarding potential reliability benefits of the proposed standard, we agree that ride-through issues at some IBRs have presented a legitimate reliability concern. However, the recent adoption of Federal Energy Regulatory Commission (FERC) Order 2023 directly addresses many of those concerns by imposing mandatory requirements to fully ride-through grid disturbances and to accurately validate models of plant performance at the sub-second transient timescale. Prior to the adoption of Order 2023, the proposed requirements of PRC-028 may have provided a significant reliability benefit by improving understanding of the ride-through performance of IBRs, and thus helping to identify solutions to any concerns. However, now that FERC Order 2023 already solved many of those concerns by requiring ride-through performance and accurate modeling of sub-second plant performance, it is not clear what reliability benefit PRC-028 might provide.

The proposed PRC-028 requirements would impose a considerable cost and burden on generators. While R1 and the 2.2.3. subpart of R2 that requires fault recording for “DC bus current and voltage” have an exemption that “IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded,” but R3 and the other parts of R2 appear to apply retroactively to all IBR plants. Retroactive requirements impose a much greater financial burden on the generator as those costs cannot typically be recovered once a power purchase agreement has been signed, and the cost and implementation burden for retrofits is typically much higher than if the data collection equipment were planned and installed as part of initial plant construction. Moreover, retroactive requirements set a bad precedent and introduce regulatory uncertainty that makes generation investment more challenging and risky, and thus costly. In some cases the cost of installing the required data collection, storage, and transmission equipment and associated auxiliary equipment could approach $1 million per plant, in addition to ongoing operations and maintenance and compliance costs associated with that equipment. The requirement in R3 for the fault recorder at each IBR unit (which footnote 2 defines as each inverter or wind turbine generator) to report at least 128 samples per cycle for over two seconds per event necessitates the use of expensive high-speed sensing equipment at each IBR unit, and requires each recorder to capture, store, and transmit at least 15,000 datapoints per event.

To make the cost of PRC-028 more reasonable while preserving the value of the proposed data collection, as well as avoiding undue discrimination against IBRs relative to synchronous generators, we suggest that data collection in PRC-028 only be required prospectively and not retroactively, and only at plants that are 500 MVA and greater, which is the plant size threshold at which synchronous generator data collection is required in the PRC-002 standard. If the TO or RC/PC can compellingly demonstrate that smaller new plants should be required to comply with PRC-028's data collection requirements due to local reliability concerns, such as weak grid issues or high penetrations of IBRs in a local area, then that should be allowed.

In addition, the cost of installing a sequence of event recorder and fault recorder on the last 10% of each collector feeder per R1 and R2 is significant, as large IBR plants can each contain dozens of collector feeders. Moreover, the fact that IBR plants typically consist of multiple collector feeders with similar if not identical equipment connected to them casts further doubt on the value of installing data collection devices on each collector feeder, as the impact of the disturbance and the IBR response is likely to be similar if not identical across those feeders. Even more burdensome is that R3 requires fault recorders to be installed at each IBR unit, which footnote 2 defines as each inverter or wind turbine generator. IBR plants typically consist of dozens if not hundreds of IBR units that are essentially identical. As a result, a more reasonable requirement would be for data collection equipment to be installed on a single collector feeder or IBR unit at each plant, which should allow extrapolation of that data to other collector feeders or IBR units at the plant. If a plant contains multiple types of inverters or wind turbine generators, it may be reasonable to require data collection on each feeder or unit that uses a different inverter or generator type.

Given that there are finite resources for complying with all NERC requirements, and in light of the fact that the ride-through concerns PRC-028 is attempting to understand have already been addressed by FERC Order 2023, we are concerned that PRC-028 as proposed could actually undermine reliability by distracting from more pressing reliability needs. We believe the revisions we have proposed will result in a standard that better balances the cost of complying with standard with its reliability benefit.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. Additionally, the recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.

The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of “each” collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

*The NAGF notes that the cost to purchase and install monitoring equipment will vary by company. NAGF members estimates range from $100,000 to $450,000 per feeder at an IBR generation facility. High end estimate is based on having to build a new structure to house the equipment, get power and communications to it, and digging up the collector circuit to connect the equipment. Lower estimate is based on installing the recording equipment within the IBR unit, leveraging the use of existing instrument transformers, and integrating I/O from existing IBR OEM control systems. Note that having to install monitoring equipment to the IBR unit connected to last 10% of **each** collector feeder length (i.e., furthest from the collector bus) in an IBR generation facility will be expensive; a wind farm that has 14 feeders, installing DFR equipment just on those 14 feeders at that single Facility, would have an estimated cost of between $1,400,000 – $6,300,000. Modifications would also be needed for the associated substation to install additional metering and RTACs (along with programming work), communication wiring, etc. Considering the number of existing BES IBR generation facilities, the cost would be in the billions of dollars to install. The concern is that the reliability benefit of installing such equipment does not justify the cost.*

Likes 0	
Dislikes 0	

Response

Thanks for your comment. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI is concerned that proposed PRC-028-1 does not align with the approved SAR scope and if approved would place unreasonable costs on registered entities without adequately balancing costs as required by the SAR. We further note that the SAR Scope states that "it is important that **some of these resources and nearby BES elements are monitored with DDR devices** to ensure adequate coverage for disturbance analysis while balancing cost impacts." The SAR does not intend that all IBR facilities need to have the level of monitoring proposed. To address this concern, the SDT should develop criteria that allows entities to select a representative number of sites in order to ensure adequate analysis of IBR performance.

Likes 0	
Dislikes 0	

Response

Thanks for your comments. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for

FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation is concerned about the possible cost involved in implementing the Fault Recording (FR) sampling rate that PRC-028 is requiring. SEL-300 series relays are used extensively throughout the industry and do not meet the required sampling rate proposed by PRC-028. If PRC-028 is approved with these required parameters many BES IBR facilities would be required to upgrade to SEL-400 series relays. This wholesale replacement for relay types would also require planned outages to facilitate. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. The minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR is in support of the EEI comment.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation is concerned about the possible cost involved in implementing the Fault Recording (FR) sampling rate that PRC-028 is requiring. SEL-300 series relays are used extensively throughout the industry and do not meet the required sampling rate proposed by PRC-028. If PRC-028 is approved with these required parameters many BES IBR facilities would be required to upgrade to SEL-400 series relays. This wholesale replacement for relay types would also require planned outages to facilitate. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	

Because of the reliability need to assess IBR performance during disturbances, the use of current fault recorder technology and associated cost of installation is the best solution. The staged implementation plan also allows entities five (5) years to implement changes so as not to overwhelm the supply chain or overburden staff resources. Please note ERCOT is a member of the ISO RTO Council Standards Review Committee but for their own reasons elect not to support this response to Question #3.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	

Cost effectiveness cannot be known at this time.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy's focus is to assure the effective and efficient reduction of risks to the reliability and security of the grid and will not provide comments on the cost effectiveness of the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
WECC will not comment on the cost effectiveness, but will leave that to applicable entities.	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC will abstain from answering Question 3.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Considering all comments received, many changes are made to the standards PRC-002/028 and the implementation plan.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports the NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to NPCC RSC's comments.	

4. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Although PRC-028 Implementation Plan mirrors the existing PRC-002-1 Implementation Plan, PRC-028 will require all BES IBRs to install DME. Depending on the number of BES IBR locations owned by the GO, this could possibly result in numerous new DME installations that will be more challenging to coordinate and schedule compared to the implementation of PRC-002-1. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	

Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to IRC SRC's comments.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR requests review of revised PRC-002 and PRC-028 prior to agreeing to the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Considering all received comments, changes are made to standards and the implementation plan.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	

The Implementation Plan should explicitly require any new interconnected facilities that fall under the PRC-028-1 Applicability section to be compliant on or before the date of commercial operations. There is no need to stage the phase-in over 5 years for new construction.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The implementation plan is revised. Clarification is provided for facilities entering commercial operation after the effective date of the PRC-028.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Although PRC-028 Implementation Plan mirrors the existing PRC-002-1 Implementation Plan, PRC-028 will require all BES IBRs to install DME. Depending on the number of BES IBR locations owned by the GO, this could possibly result in numerous new DME installations that will be more challenging to coordinate and schedule compared to the implementation of PRC-002-1. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires	

Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF provides the following implementation plan comments for consideration:

a. General: Request the SDT to consider revising the Implementation Plan to address when a new IBR generation facility is to be compliant with PRC-028-1.

b. Page 2, "Compliance Date for PRC-028-1 Requirements R1-R7" section:

i. Recommend revising the first paragraph such that the time period for 100% of an entities IBR generation facility to be compliant is three (3) years instead of the proposed two (2) year time limit.

ii. Recommend deleting the third paragraph as it does not provide any value for the implementation plan.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order

901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028. Recommendation to share implementation strategy with ERO Compliance Monitoring and Enforcement Program staff is removed.

Michiko Sell - Pine Gate Renewables - 5	
Answer	No
Document Name	
Comment	
For PRC-028 we are concerned with availability of needed devices for installation. Consider adding an additional traunch and extend full implementation by a year. Also consider MW size of Facilities since this is a reliability assurance issue.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply	

chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan.

Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028. Additional milestones in the implementation plan may be unnecessarily burdensome.

The PRC-028 standard would apply to all IBRs that meet the Inclusion I4 of the BES definition. As directed by recent FERC Orders (Order No. 901 and IBR Registration Order), the standard would also apply to Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. Refer to technical rationale for more details.

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power agrees with the PRC-002-5 implementation plan.

For the PRC-028-1, Minnesota Power's comments are aligned with the MRO NSRF and suggest a time frame of 6 calendar years to meet the 100% requirement.

Likes 0	
Dislikes 0	

Response

Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring

equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Concerns about PRC-028 applicability and data requirements will need to be addressed before the implementation plan can be supported.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Considering all received comments, changes are made to proposed requirements in PRC-028 as well as the implementation plan.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
It is ACES’ opinion that the proposed changes to PRC-002 are minimal; therefore, the timeline identified in the Implementation Plan is appropriate.	

As for the proposed timeline for PRC-028-1 R1-R7 identified in the Implementation Plan, it is ACES' opinion that the timelines identified for 50% and 100% compliance should be equal. We recommend the following change:

"…fully compliant at 100% of their generating plant/Facilities within six (6) calendar years of the effective date of Reliability Standard PRC-028-1."

Lastly, while an individual entity's compliance with a given requirement is auditable, their strategy for how they will manage their compliance is not auditable. Therefore, the requirement that an entity share their implementation strategy for PRC-028-1 R1-R7 with the ERO Compliance Monitoring and Enforcement Program staff should be struck from the Implementation Plan.

Likes 0	
Dislikes 0	

Response

Thanks for your comments.

Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan.

Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028.

Recommendation to share implementation strategy with ERO Compliance Monitoring and Enforcement Program staff is removed.

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to MRO NSRF's comments.	
Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	
Comment	
PG&E does not support the time frame in the current implementation plan without an exception (see the input to Question 5, item #1 below) for existing applicability to facilities at the Transmission Owner (TO) Point of Interconnection (POI). An exemption clause is given to preexisting IBR facilities (GO). At present, no TO exemption exists at the Point of interconnection. This requires installation of equipment, or replacement of existing equipment, at the POI for all identified IBR facilities. We recommend providing a TO exemption similar to that granted for GO, particularly if the bus had been identified under PRC-002 and has equipment installed to comply with PRC-002. An alternative is to make PRC-028 FR/SER/DR performance requirements identical to PRC-002.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comments. See response to MRO NSRF’s comments.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to NAGF’s comments.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The PRC-002-5 implementation plan is fine as proposed (immediate) since the previous requirements did not change for the synchronous units. The two partitions of completion proposed, 50% & 100%, should be given equal time periods since the %'s are split in half - that is, the 100% time period should be "within six (6) calendar years of the effective date of PRC-028-1" (rather than in 5 calendar years). Entities should not have to share their strategy for implementation with the ERO Compliance Monitoring and Enforcement Program staff. This requirement should not be in the implementation plan.	

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

Thanks for your comments.

Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan.

Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028.

Recommendation to share implementation strategy with ERO Compliance Monitoring and Enforcement Program staff is removed.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

The PRC-002-5 implementation plan is fine as proposed (immediate) since the previous requirements did not change for the synchronous units.

The two partitions of completion proposed, 50% & 100%, should be given equal time periods since the %'s are split in half - that is, the 100% time period should be "within six (6) calendar years of the effective date of PRC-028-1" (rather than in 5 calendar years).

Entities **should not** have to share their strategy for implementation with the ERO Compliance Monitoring and Enforcement Program staff. This requirement should not be in the implementation plan. The 100% compliant date given for R8 doesn't make sense because there may not be any DME installed at the time specified. Consider using this, "R8 is be applicable to each DME installation upon completion of the installation and commissioning of the DME equipment."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028. Recommendation to share implementation strategy with ERO Compliance Monitoring and Enforcement Program staff is removed. Compliance date for R8 is also clarified.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	

Comment	
NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See responses to other opposing comments. The implementation plan is revised considering comments received.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See responses to other opposing comments. The implementation plan is revised considering comments received.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comments. See responses to other opposing comments. The implementation plan is revised considering comments received.	
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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments: It is ACES' opinion that the proposed changes to PRC-002 are minimal; therefore, the timeline identified in the Implementation Plan is appropriate.	

As for the proposed timeline for PRC-028-1 R1-R7 identified in the Implementation Plan, it is ACES' opinion that the timelines identified for 50% and 100% compliance should be equal. We recommend the following change:

"…fully compliant at 100% of their generating plant/Facilities within six (6) calendar years of the effective date of Reliability Standard PRC-028-1."

Lastly, while an individual entity's compliance with a given requirement is auditable, their strategy for how they will manage their compliance is not auditable. Therefore, the requirement that an entity share their implementation strategy for PRC-028-1 R1-R7 with the ERO Compliance Monitoring and Enforcement Program staff should be struck from the Implementation Plan.

Likes 0	
Dislikes 0	

Response

Thanks for your comments.

Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan.

Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028.

Recommendation to share implementation strategy with ERO Compliance Monitoring and Enforcement Program staff is removed.

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	

Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation supports a 18-month implementation time frame.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028. The compliance date for R8 is also revised.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
Given BC Hydro's comments to Question #3 above, and pending additional clarifications, BC Hydro is unable to support the proposed Implementation Plan at this stage.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to Question #3. Also note that considering other comments, the implementation plan is revised. Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1	

through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
Entities should have to submit a plan that is approved by the Region as being reasonable. It is difficult to determine the number of facilities and how much equipment may have to be addressed by companies that will be impacted. Timelines are clean, but do not always represent the real-life situations that must be addressed.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply	

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Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Until the definition of inverter-based resources is clearly defined, then FE would be supportive of the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Talen supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Refer to response to NAGF's comment.
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	
Comment	
The PRC-002-5 implementation plan is fine as proposed (immediate) since the previous requirements did not change for the synchronous units. The two partitions of completion proposed, 50% & 100%, should be given equal time periods since the %'s are split in half - that is, the 100% time period should be "within six (6) calendar years of the effective date of PRC-028-1" (rather than in 5 calendar years). Entities should not have to share their strategy for implementation with the ERO Compliance Monitoring and Enforcement Program staff. This requirement should not be in the implementation plan. The 100% compliant date given for R8 doesn't make sense because there may not be any DME installed at the time specified. Consider using this, "R8 is applicable to each DME installation upon completion of the installation and commissioning of the DME equipment."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply	

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Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Until further clarifications are provided regarding our expressed concerns, AEP would be unable to support a proposed Implementation Period.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to other comments and changes made to PRC-002/028 standards.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	

With the timline provided it may be difficult to procure proper equipment in time to meet requirements.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028.	
Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF	
Answer	No
Document Name	
Comment	
The implementation plan for PRC-028-1 is to short of a time frame. 50% within in 3years won't happen due to industry wide material and equipment shortages and delays. Implementation should be extended to at least a minimum of 7 years at 50%.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comments. The implementation plan is revised. In an initial posting, Entities were required to comply with Requirements R1 through R7 at 100% of their generating plants/Facilities within five (5) calendar years of the effective date PRC-028. However, the FERC Order 901 directs that the standard is fully effective and enforceable before 2030 (see P226). The implementation plan is revised and requires Entities to comply with Requirements R1 through R7 at 100% of their generating plant/Facilities by January 1, 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Further clarification is provided for facilities entering commercial operation after the effective date of the PRC-028.	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the implementation plan. Considering all received comments, the implementation plan is revised. Please review the revised implementation plan.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the implementation plan. Considering all received comments, the implementation plan is revised. Please review the revised implementation plan.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports the NPCC RSC’s comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NPCC RSC’s comments.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed phased Implementation Plan.	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	Yes
Document Name	
Comment	
Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Phased implementation plan is acceptable.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	

Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Phased implementation plan is acceptable.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Phased implementation plan is acceptable.	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Ruida Shu - Northeast Power Coordinating Council - 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	
Thanks for your support.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

5. Provide any additional comments for the standard drafting team to consider, if desired.	
Wendy Devries - CMS Energy - Consumers Energy Company - 1,2 - RF	
Answer	
Document Name	
Comment	
PRC-028-1 should state clearly how to determine if IBRs are capable of recording or not. IBRs downstream of a feeder shouldn't be monitored as they aren't BES assets.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Refer to the Bulk Electric System Definition Reference Document, version 2 dated April 2014. Examples provided in figures 14-1 through 14-4 show that IBR units connected to collector feeders could be BES Elements.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	
Document Name	
Comment	
Section 1.2. Agree with the exclusion for IBRs that are currently installed. No issues with IBR fault codes, alarms, etc but the operating mode, voltage/frequency ride-through, and control system values are either static configuration parameters or operational values which are not sequence of event points. Section 4. Agree with section 4 and it is the most important for analyzing localized or wide spread events.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. See revised requirements. The SDT recognizes that voltage/frequency ride-through mode status values are static in nature. The intent is to record change of status each time IBR unit enters or exits the ride-through mode.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

While AEP supports the efforts of the Standards Drafting Team and their overall direction in Phase II, we are concerned by what we perceive as an excessiveness of data granularity, especially when compared to those of synchronous machines in PRC-002. The follow items are of specific concern.

1) R3.1.2. – We see no justification for, nor reliability benefit in, requiring a minimum recording rate of 128 samples per cycle. The sample rate is eight times greater than that used for synchronous machines in the equivalent requirements of PRC-002, and far exceeds the maximum sampling rate of many relay models currently used. AEP would like to suggest instead using 16 samples per cycle.

2) Subparts of R1.2 – AEP questions the reliability benefit in requiring the data specified in the subparts, which includes data not captured as "sequence of events." In addition, why would this data be necessary for IBRs but not for synchronous machines?

AEP also questions the necessity of providing the data as several projects are currently underway to address the impact IBRs have had on the BES. The purpose of Project 2020-02 is to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances. Specifically, this SAR focuses on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. The SAR also ensures protection or controls that fail to ride through system events are analyzed, addressed with a corrective action plan (if possible), and reported to necessary entities for situational awareness.

3) 7.1 through 7.5 – As currently written, the requirements set no expectations to encourage a timely request for data, which may put data availability at risk. The Technical Rationale states "if a request for the data is made on Day 31, that is outside the 30 calendar days specified in

the requirement, and an entity would not be out of compliance if it did not have the data", however this is not made explicitly clear within the requirements themselves. In addition, recording devices often save and discard data using a "first in / first out" methodology, so thirty full days of meaningful data may not be available if a request is made several weeks after an event. The obtainer of the data needs ample opportunity to retrieve the data after the request, and if a request is made at the end of the allowable 30 day window, it is very possible that some of the desired data may no longer be available. The data at most risk for omission would be pre-event data as well as data at the time of the event. As a result, data "inclusive of the day the data was recorded" may no longer be available. To address the core of our concerns, clarity is needed regarding the standard's expectations regarding the minimum time period that a device is expected to retain historical information. As currently written, the standard seems to infer that a device might need to retain as many as 60 days of data in order to properly fulfill a request made 30 days after an event occurs. In addition, there is no specificity given regarding how much of the 30 days of data provided be either pre- or post-event.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. IBRs are fast acting devices and hence the higher sampling rate is needed. However, considering comments, the minimum recording rate for FR data is reduced to 64 samples per cycle. R1 Part 1.2: This data would be helpful to understand the operation of IBR unit during a disturbance. The FR/DDR data recorded under the PRC-028 standard would be used to analyze performance of IBRs during system disturbances. This data will also be used for model validation. The data collected under this standard is anticipated as pre-requisite for proposed PRC-029 and PRC-030 standards. The data retrievable period in Requirement R7 is reduced to 20 calendar days from initially proposed 30 calendar days.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	

Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the drafting teams approach to PRC-002 and PRC-028 except for the creation of standard specfic defined terms for "inverter based resource (IBR)" and "IBR unit". Currently there are at a minimum of 8 active NERC projects under development to address various IBR reliability issues, multiple projects contain inconsistent standard specific defined terms for IBR and IBR unit. NERC should coordinate with industry to develop BES glossary terms for IBR and IBR unit and apply the terms to all applicable standards.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The project 2020-06 SDT is developing definitions for IBR and IBR unit.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

A) Applicability section 4.2.5 is confusing. Is this facility item attempting to identify the required locations for DME to be added? If so, this is out of place and needs to be addressed in a requirement rather than in the applicability section only as is done in R1, 1.2.

B) In requirement R1 sub-parts 1.2.4 and 1.2.5, it is not clear what is desired to be recorded in the SER data.

C) There are multiple control systems in play at these facilities - Requirement R1, sub-part 1.2.6 needs to be very specific to which control system, which command value, which reference value, and which feedback signals are required to be monitored. Further, these signals are not well suited for SER recording, which typically are dry contact inputs used to determine the order of events rather than the time-variation of control and process variables.

D) Requirement sub-parts 3.1.3, 3.2.3, and 3.3.3 need to specify values to be considered as an (ac/dc) overvoltage condition, (ac/dc) undervoltage condition, (ac/dc) overcurrent condition, dc reverse current condition, over frequency condition, underfrequency condition.

E) The inclusion of NERC as a recipient of information upon a request is not appropriate. NERC has other means of obtaining information that should be used, including Section 1600 data requests or NERC Alerts.

Likes 0	
Dislikes 0	

Response

Thanks for your comments.

The applicability section is revised. Parts 4.2.1 – 4.2.5 are removed.

Requirement R1, subpart 1.2.6 refers to control system associated with the IBR unit. Specifying generic values for declaration of (ac/dc) overvoltage condition, (ac/dc) undervoltage condition, (ac/dc) overcurrent condition, dc reverse current condition, over frequency condition, and underfrequency condition is not possible. These values should be chosen based on equipment design, operating experience etc. Regarding NERC as a receipt of information upon a request comment, the standard drafting team reviewed this comment with NERC Staff, and disagrees that alternate mechanisms under the Rules of Procedure (Section 1600 request for information or a NERC Alert) are more appropriate for obtaining time-sensitive disturbance monitoring data under the requirements. Additionally, this language is modeled on approved PRC-002-4.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
NERC Alert R-2023-03-14-01 Level 2 – Inverter-Based Resource Performance Issues (NERC Alert) and NERC Project 2021-04 PRC-028-1 (PRC-028-1) information appear to not align. For example: (a) NERC Alert information appears to be missing from SER/FR/DFR data requests. Is any of the following information needed to perform wide area analysis, fault analysis, other? While the following three items may possibly be included as specifications required in interconnect agreement data, are they also needed for PRC-028 requirements? • Active Power Ramp Rate (after momentary cessation) • Recovery time delay • Momentary Cessation- if in use- (may be covered by fault alarm (1.2.2) and operating mode change (1.2.3)	

(b) Are the below listed signals intended to be covered by R1.2.6 Control system command values, reference values, and feedback signals of the new 28 standard? Are they values that will impact the analysis performed by the RCs and BAs? The following were of concern in the NERC Alert:

• frequency tripping time delay

• frequency tripping inhibit (if used)

• droop performance-this is affected by FERC Order No. 842

• Indication if ramp rate is being controlled by individual unit versus by plant level controller

• Typically, if plant voltage level falls below its continuous operating range the individual inverters control operation – *does this constitute a change in operating mode as covered in R1.2.3?*

• Maximum Power Point Tracking (MPPT) controls (if MPPT function was frozen to pre-contingency value or reset to default).

(c) The NERC Alert highlights the following items. Should they be included in PRC-028-1 as triggers:

• Inverter Instantaneous AC Voltage tripping

• Inverter Instantaneous AC overcurrent

• Inverter phase lock loop loss of sync

• Inverter DC unbalance tripping

Are any point of measure (POM) or point of interconnect (POI) triggers besides the following needed:

• 3.1.3.1. Neutral (residual) overcurrent and

• 3.1.3.2. AC phase overvoltage and undervoltage

Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The intent of PRC-028 is to have recording available from IBR unit and IBR plant that shows plant's performance during a disturbance for use with performance evaluation and model validation. Most items mentioned in comment are appropriate details to be reflected in IBR models.	
Donald Lock - Talen Generation, LLC - 5	
Answer	
Document Name	
Comment	
Talen supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FE supports EEI's comments which state: **EEI Comments on PRC-028-1**: **Purpose Statement**: EEI does not agree that the purpose statement for this Reliability Standard aligns with the intended scope of this project. To address this concern, we offer the following edits in boldface:	

To have adequate data available from **a representative number of** inverter-based resources (IBR)**/Facilities** to facilitate **the** analysis **of IBR performance during** Bulk Electric System (BES) Disturbances.

Functional Entities: EEI does not agree with the Functional Entities as listed. We believe that PRC-028 should also include Reliability Coordinators (RC) in this list, noting that the SAR was never intended to require monitoring of IBRs at all locations. Instead, the SDT should develop a criteria for identifying where and when monitoring should be installed and the RC should be the entity that 1) utilizes that criteria to determine where monitoring is needed and 2) notifies owners of their obligations.

Applicability Section: EEI does not agree with the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in the BES Definition, Inclusion I2. (See EEI comments for Question 1)

All Requirements: EEI does not agree that this project was intended to monitor all IBRs or IBR Facilities. In the SAR it clearly states that the intent is to install DDR at some locations, not all locations. The SAR also stated that the requirements were to be balanced against costs which given the magnitude of the proposed requirements, it is difficult to see where costs were adequately balanced.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events.

The recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs. As such, inclusion of Reliability Coordinator as an applicable Functional Entities is not required.

The Inclusion I2 of the BES definition is removed from the Applicability section.

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Reclamation does not agree with the modifications to the wording of BES Elements in R6 and R7 in the "Violation Severity Levels" section. 'Element' is sufficiently defined in the NERC Glossary of terms and 'BES Element' encompasses the required equipment (elements) for Disturbance Monitoring. Reclamation recommends keeping the original wording "for all applicable BES Elements". Reclamation concurs that all IBR resources should have and maintain their own separate standards.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The comment referring to VSL of R6 and R7 is in regard to PRC-002. The revision is to provide clarity and is based on SDT member's experience since the enforcement of PRC-002.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	

Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	

Comment	
Black Hills Corporation agrees with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC has signed on to ACES comments: Firstly, Section 4.2 of the proposed Reliability Standard PRC-028-1 is somewhat confusing and seems to be a bit redundant; specifically, sections 4.2.1 and 4.2.5. It appears that these specific sections are dictating where specific equipment should be installed in addition to the locations specified in the various requirements of the standard. We recommend using an approach similar to the one used in PRC-002-5 Section 4.2. To accomplish this, we recommend using the following verbiage: "BES Elements associated with inverter-based portions of generating plants/Facilities meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition." Secondly, Requirements 1.2.4 and 1.2.5 are unclear as to what values are to be recorded. We recommend that additional clarification be made to these sections. Thirdly, Requirement 1.2.6 seems to be out of place. In a typical Sequence of Event Recording setup digital inputs are used to determine the specific sequence of occurrence for recorded events. The signals identified in Requirement 1.2.6 are typically analog signals that vary over	

time in response to process conditions. We recommend either removing this requirement altogether or being much more specific as to what information should be collected and how. Lastly, we disagree with the approach that NERC should be able to request information from an entity directly via a Reliability Standard requirement. Please note that we are not opposed to NERC requesting this information nor do we think it is inappropriate for NERC to receive said data. We do however disagree with the method of collection. It is our opinion that NERC should utilize the existing data collection mechanisms (i.e. Section 1600 data requests, NERC Alerts, etc.). Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. Sub-parts 4.2.1 through 4.2.5 in Section 4.2 are removed and where necessary, those BES Elements are included in the requirements itself. Requirement R1, Part 1.2 is revised based on received comments. Regarding NERC as a receipt of information upon a request comment, the standard drafting team reviewed this comment with NERC Staff, and disagrees that alternate mechanisms under the Rules of Procedure (Section 1600 request for information or a NERC Alert) are more appropriate for obtaining time-sensitive disturbance monitoring data under the requirements. Additionally, this language is modeled on approved PRC-002-4.	
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; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	
Document Name	

Comment	
Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comments.	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	
Document Name	
Comment	
PRC-028 - If the point of 4.2.5 is to monitor the individual inverter performance prior to being summed into a collector system, I would consider mandating the last IBR on each feeder is monitored, rather than one of the IBR units in the last 10% of each feeder.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT agrees that monitoring the last IBR unit on each collector feeder would be ideal. However, realizing that in some cases, monitoring last IBR unit may not be feasible, and hence monitoring an IBR unit connected to “last 10% of collector feeder length” allows for some flexibility. Note that considering other comments, the language is revised to “at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus”.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

A) Applicability section 4.2.5 is confusing. Is this facility item attempting to identify the required locations for DME to be added? If so, this is out of place and needs to be addressed in a requirement rather than in the applicability section only as is done in R1, 1.2.

B) In requirement R1 sub-parts 1.2.4 and 1.2.5, it is not clear what is desired to be recorded in the SER data.

C) There are multiple control systems in play at these facilities - Requirement R1, sub-part 1.2.6 needs to be very specific to which control system, which command value, which reference value, and which feedback signals are required to be monitored. Further, these signals are not well suited for SER recording, which typically are dry contact inputs used to determine the order of events rather than the time-variation of control and process variables.

D) Requirement sub-parts 3.1.3, 3.2.3, and 3.3.3 need to specify values to be considered as an (ac/dc) overvoltage condition, (ac/dc) undervoltage condition, (ac/dc)overcurrent condition, dc reverse current condition, overfrequency condition, underfrequency condition.

Likes 0	
Dislikes 0	

Response

Thanks for your comments.

Sub-parts 4.2.1 through 4.2.5 in Section 4.2 are removed and where necessary those BES Elements are included in the requirements itself.

Requirement R1, subpart 1.2.6 is removed.

Specifying generic values for declaration of (ac/dc) overvoltage condition, (ac/dc) undervoltage condition, (ac/dc) overcurrent condition, dc reverse current condition, over frequency condition, and underfrequency condition is not possible. These values should be chosen based on equipment design, operating experience, etc.

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	

Document Name	2021-04.PNG

Comment

1. PRC-028 applicability section 4.2.5 is confusing. Is this facility item attempting to identify the required locations for DME to be added? If so, this is out of place and needs to be addressed in a requirement rather than in the applicability section only as is done in R1, 1.2.

2. PRC-028 in requirement R1 sub-parts 1.2.4 and 1.2.5, it is not clear what is desired to be recorded in the SER data.

3. There are multiple control systems in play at these facilities – PRC-028 Requirement R1, sub-part 1.2.6 needs to be very specific to which control system, which command value, which reference value, and which feedback signals are required to be monitored. Further, these signals are not well suited for SER recording, which typically are dry contact inputs used to determine the order of events rather than the time-variation of control and process variables.

4. PRC-028 Requirement sub-parts 3.1.3, 3.2.3, and 3.3.3 need to specify values to be considered as an (ac/dc) overvoltage condition, (ac/dc) undervoltage condition, (ac/dc)overcurrent condition, dc reverse current condition, overfrequency condition, underfrequency condition.

5. The inclusion of NERC as a recipient of information upon a request is not appropriate. NERC has other means of obtaining information that should be used, including Section 1600 data requests or NERC Alerts.

6. For SER data in R1.2 (PRC-028), what is acceptable proof of exclusion for IBR units installed prior to the effective date of this standard and not capable of recording this data?

7. In PRC-028 it is recommended there be an exclusion similar to R1.2 for FR data in R2.2 and R3.2 for IBR units installed prior to the effective date of this standard that are not capable of recording this data with the required triggering, length, or sample rate. If permitted, what is acceptable proof of exclusion?

8. In PRC-028 it is recommended there be an exclusion similar to R1.2 for FR data in R2.3 and R3.3 for dynamic reactive units installed prior to the effective date of this standard that are not capable of recording this data with the required triggering, length, or sample rate? If permitted, what is acceptable proof of exclusion?

9. In PRC-028 for SER and FR data in sections R1.2, R2.2, R2.3, R3.2 and R3.3, please clarify the exclusion applies if only some data recording capability is available but not all data that the data that is available. It seems cleaner to exclude these units completely rather than use a more complex piecemeal method which may be difficult to audit.

10.Would the following situation be considered a possible violation in PRC-028? There is a discovery of recorder failure as noted may occur in R8 during a time when data was requested per R7? (recorded data is not available due to the failure)

11. The PRC-028-1 technical rationale on page 2 states: "*The standard is only applicable to Transmission Owner in case where Transmission Owner owns equipment within the IBR Plant." Should "equipment" be clarified that it is applicable to monitored elements such as breakers, transformers, reactive units or IBRs?*

12. Review the two figures called scenario 1 and scenario 2 and clarify PRC-028 applicability. Consider that Trans owner bus may or may not be applicable for PRC-002.

Consider if there may be a registration or information gap where (GO) IBR/wind/solar owners that are less than 75MVA may need to comply with PRC-028 due to the >75MVA aggregation threshold.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

Thanks for your comments.

The applicability section is revised. Parts 4.2.1 – 4.2.5 are removed.

Requirement R1, Part 1.2 is revised.

Specifying generic values for declaration of (ac/dc) overvoltage condition, (ac/dc) undervoltage condition, (ac/dc) overcurrent condition, dc reverse current condition, over frequency condition, and underfrequency condition is not possible. These values should be chosen based on equipment design, operating experience, etc.

Regarding NERC as a receipt of information upon a request comment, the standard drafting team reviewed this comment with NERC Staff, and disagrees that alternate mechanisms under the Rules of Procedure (Section 1600 request for information or a NERC Alert) are more appropriate for obtaining time-sensitive disturbance monitoring data under the requirements. Additionally, this language is modeled on approved PRC-002-4.

Requirement R1, Part 1.2 is revised. The term “installed” is replaced with “commercial operation” and also added term “without modification” for clarity.

The exclusion in R1, Part 1.2 recognizes limitation of IBR units in commercial operation before the effective date of this standard. Such exclusion is not necessary for dynamic reactive device connected to the collector bus.

The SDT cannot comment on comment #10.

Comment #11: Clarified as suggested.

The standard applies to facilities meeting the Inclusion I4 of the BES definition. As directed by recent FERC Orders (Order No. 901 and IBR Registration Order), the standard would also apply to Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. Refer to technical rationale for more details.	
Mark Fowler - Mark Fowler On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Mark Fowler	
Answer	
Document Name	
Comment	
Ameren would like more clarification around R2.2, specifically the phrase “IBR unit connected to 10% of each collector feeder length.” 2.2.3: Are they referring to a DC collection system as opposed to a DC to AC conversion at each wind turbine or solar panel? Ameren is confused as to how we would collect this data. Ameren also supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard does not refer to DC collection system. Please refer to examples included in the technical rationale.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	

As stated in our response to question 3 above, AZPS does not agree that the SAR intended that all IBR facilities should be monitored. Instead, there should be a criteria for identifying where and when monitoring should be installed similar to PRC-002 and the RC should be the entity that determines where monitoring is needed and notifies owners of their obligations.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. Additionally, the recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs. As such, inclusion of Reliability Coordinator as an applicable Functional Entities is not required.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	

Answer	
Document Name	
Comment	
WEC Energy Group supports the additional comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to NAGF's comments.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	
In PRC-002-5 Attachment 1, Bulk Electric System (BES) is spelled out in step 1 despite the acronym being used earlier in the Attachment and SER and FR acronym description are removed. All 3 terms are spelled out and acronyms identified in PRC-002-4 standard. Acronyms only are sufficient for all 3 in Attachment 1. In Figure 2 of the PRC-028-1 Technical Rationale, it is clear the TO breaker on the generator tie line is not applicable. Please clearly identify this in the applicability section of the standard to avoid confusion between GOs and TOs for 4.2.1 Add a figure of an IBR interconnection without local high-side transformer breaker to the transmission system via transmission line to a Transmission Owner Ring Bus Substation. Clarify that the Transmission owner ring breakers do not have PRC-028-1 SER/FR responsibilities.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The BES, SER, and FR are spelled out first time they appear in Attachment 1 of PRC-002. PRC-028 Technical Rationale – The example related to Figure 2 (figure 2 in revised technical rationale) clearly states that “The SER and FR data requirements for the identified BES bus are per the requirements in the Reliability Standard PRC-002.” The project 2020-06 SDT is defining IBR, which will be used in PRC-028. The use of defined term would take care of last comment.

Michael Johnson - Michael Johnson On Behalf of: 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 has the following additional input: 1 – PG&E believes the current wording of Requirement R1, Part 1.2 provides an exception for the Generator Owner (GO) for units installed prior to the effective date of the standard but is not clear the exception would be provided to the Transmission Owner (TO). This is based on the text of “… IBR unit connected to the last 10% of each collector feeder length.” This implies that it applies to the GO since they would be part of the last 10% of the feeder length. To indicate that exemption applies to both the GO and TO, PG&E suggests the following: Take the text “IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded”, remove it from Part 1.2, and make it a footnote to the main R1 text. This would clearly indicate the exemption is for both the GO and TO.	

2 – PG&E supports the NAGF input for Question 5 regarding having a methodology like PRC-002 to determine if SER/FR equipment are required verses the current draft approach of requiring all BES facilities to have the equipment. 3 – PG&E believes the PRC-028 recorder specification (sampling rate, etc..) are more stringent then PRC-002. PG&E recommends that PRC-028 should be brought into alignment with what is indicted in PRC-002.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The exemption applies to TO as well, if TO owns IBR unit where monitoring is required. However, it is very unlikely that a TO would own an IBR unit (PV/BESS inverter, WTG, etc.) for which monitoring is required. See response to NAGF's comments. IBRs are fast acting devices requiring higher sampling rate. However, considering all comments, recording rate for FR data is reduced to 64 samples per cycle.	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. See response to MRO NSRF's comments.	
Ijad Dewan - Ijad Dewan On Behalf of: Alain Mukama, Hydro One Networks, Inc., 1, 3; - Ijad Dewan	
Answer	
Document Name	
Comment	
Not applicable	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to EEI's comments.	
Daniel Gacek - Exelon - 1	
Answer	

Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to EEI's comments.	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to EEI's comments.	
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	
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #5.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to EEI's comments.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	

Firstly, Section 4.2 of the proposed Reliability Standard PRC-028-1 is somewhat confusing and seems to be a bit redundant; specifically, sections 4.2.1 and 4.2.5. It appears that these specific sections are dictating where specific equipment should be installed in addition to the locations specified in the various requirements of the standard. We recommend using an approach similar to the one used in PRC-002-5 Section 4.2. To accomplish this, we recommend using the following verbiage:

"BES Elements associated with inverter-based portions of generating plants/Facilities meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition."

Secondly, Requirements 1.2.4 and 1.2.5 are unclear as to what values are to be recorded. We recommend that additional clarification be made to these sections.

Thirdly, Requirement 1.2.6 seems to be out of place. In a typical Sequence of Event Recording setup digital inputs are used to determine the specific sequence of occurrence for recorded events. The signals identified in Requirement 1.2.6 are typically analog signals that vary over time in response to process conditions. We recommend either removing this requirement altogether or being much more specific as to what information should be collected and how.

Lastly, we disagree with the approach that NERC should be able to request information from an entity directly via a Reliability Standard requirement. Please note that we are not opposed to NERC requesting this information nor do we think it is inappropriate for NERC to receive said data. We do however disagree with the method of collection. It is our opinion that NERC should utilize the existing data collection mechanisms (i.e. Section 1600 data requests, NERC Alerts, etc.).

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Thanks for your comments.

Sub-parts 4.2.1 through 4.2.5 in Section 4.2 are removed and where necessary, those BES Elements are included in the requirements itself.

Considering received comments, Requirement R1, Part 1.2 is also revised.

Regarding NERC as a receipt of information upon a request comment, the standard drafting team reviewed this comment with NERC Staff, and disagrees that alternate mechanisms under the Rules of Procedure (Section 1600 request for information or a NERC Alert) are more appropriate for obtaining time-sensitive disturbance monitoring data under the requirements. Additionally, this language is modeled on approved PRC-002-4.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Thanks for your support.
Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

AES Clean Energy questions the reliability need for the proposed requirements at all IBRs because this goes beyond what is required at traditional synchronous plant facilities under current PRC-002. As stated in the Purpose statement, the intent of this Reliability Standard is to "have **adequate** data available from inverter-based resources (IBR) to facilitate analysis of Bulk Electric System (BES) Disturbances." This implies that the needs are not everywhere for data to assist in analyzing disturbance events. AES Clean Energy recommends the Standard Drafting Team consider adding requirement(s) for the Transmission Owner and/or Reliability Coordinator to develop a list of IBRs in their areas that require data based on a set of criteria similar to what is currently in PRC-002 and notify the affected GOs. Along with that, AES Clean Energy also recommends that Standard Drafting Team develop a set of criteria that can be used by the TO/RC to assess where disturbance monitoring equipment should be installed in their region. This set of criteria may include:

- Minimum MW/MVA threshold for IBRs requiring SER/FR/DDR
- Amount of IBRs connected in a particular area of the TO/RC region
- Level of grid strength of areas within the TO/RC region

There may be a need for a requirement for the TO/RC to assess periodically to determine a new list of IBRs, similar to PRC-002.

AES Clean Energy also urges the ERO to be considerate of the cost of installing these equipment while drafting the expecations of the standard and identify different options to ensure reliability of the interconnection. The above recommendations are to ensure that reliability is achieved through a reasonable cost approach.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. Additionally, the recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs. As such, inclusion of Reliability Coordinator as an applicable Functional Entities is not required.

The SDT is cognizant of costs associated with implementing the proposed Reliability Standard PRC-028-1. In an initial posting, the SDT proposed to require SER and FR data from at least one IBR unit connected to last 10% of "each" collector feeder. However, to balance the cost and reliability need, the SER and FR data are now required from at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus. Additionally, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle. The data retrievable period is also reduced to 20 calendar days from initially proposed 30 calendar days.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment

PRC-028-1 R1 sub-part 1.2.6 is not clear as to what control system values, reference values, and feedback signals need to be monitored.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. R1, Part 1.2.6 is removed.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	
Comment	
NPCC RSC supports the drafting team proposal.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following comments for PRC-028-1:

- Texas RE recommends the drafting team define Inverter-based Resources (IBR) as it is being used increasingly in standard requirement language and a NERC Glossary definition would drive consistency. Footnote 2 may not be clear and it is inconsistent with the footnote description of IBR in proposed EOP-004-4.
- Texas RE recommends revising the PRC-028-1 Title to include all the applicable inverter-based systems such as STATCOM, SVC, HVDC, etc., other than the traditional inverter-based resources. Texas RE recommends the following verbiage: "Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources and Dynamic Devices".
- Texas RE noticed that Section A 4.2.4 includes shunt static devices, but that device type does not appear anywhere in the requirement language. Texas RE inquires as to why this is included in section A 4.2.4
- The technical rational for PRC-028-1 states that SER data is required from all IBR units connected to last 10% of each collector feeder. Requirement 1.2, however, can be interpreted to needing the SER data from only one IBR unit from each feeder. Texas RE recommends making the requirement language consistent with the language in the technical rationale. In addition, SDT should

consider providing clarification on the ‘installed date’ for the IBRs that are excluded from this requirement, whether this date is the date at which the IBR is installed in the field or the date at which the IBR is synchronized to grid or the date of commercial operation. Additionally, the requirement should state that the Generator Owner shall document the IBR recording limitations including OEM data sheet or other equipment specifications.

  - Texas RE recommends the following verbiage for Requirement Part 1.2: “All IBR units connected to last 10% of each collector feeder length. The Generator Owner shall document the IBR recording limitations and provide the information to its Reliability Coordinator, Regional Entity, or NERC, upon request. Evidence may include OEM data sheet or other equipment specifications.”
  - Texas RE recommends the technical rationale include the following: “IBR units with commercial operation date prior to the effective date of this standard and are not capable of recording this data are excluded.”
- Texas RE seeks clarity on the sub parts of Requirement Part 1.2 regarding what specifically needs to be recorded.
- Texas RE recommends the SDT clarify whether the data included in R2.1.3 and R2.3.3 can be calculated values or not. Texas RE recommends the following verbiage for Requirement Part 2.1.3: “Three phase Real and Reactive Power (measured or calculated)”
- Requirement Part R2.2 states that IBR unit FR data is needed; however, the sub-requirements state the data can be from the unit terminals or on high-side of the IBR unit transformer. If more than one IBR units are connected to a transformer, then IBR unit level data will not be available based on the current language.
  - Texas RE recommends the language for R2 be changed to "…as applicable, at IBR unit terminals or on high-side of the IBR unit transformer if no more than one IBR is connected to a unit transformer."
- Texas RE requests the sub requirements not include the Regional Entity and NERC. Regional Entities and NERC may request data from registered entities in accordance with section 1600 of the Rules of Procedure.
- Since PRC-028 is intended to have a similar purpose as PRC-002, but specific to IBRs, Texas RE recommends PRC-028 Requirement R7 should mirror PRC-002 Requirement R11. Texas RE inquires as to why IBRs can retrieve data for 30 days while conventional units only have 10 days to retrieve data.
- Texas RE also inquires as to why the synchronized clock accuracy in PRC-028 Requirement R6 is plus/minus 100 milliseconds of UTC, but in PRC-002 Requirement R10, it is plus/minus 2 milliseconds.
- Additionally, Texas RE noticed the PRC-002 Requirement R9 output 30 times per second versus PRC-028 Requirement R5 output is 60 times per second.
- Texas RE requests the SDT update Section C Compliance to the most updated version. For example, Compliance Violation Investigations listed in section C 1.3 do not exist.

Likes 0	
Dislikes 0	

Response

Thanks for your comments.

The project 2020-06 SDT is developing definitions for IBR and IBR unit, which will be used in PRC-028 standard.

Including monitoring requirements for dynamic reactive devices and HVDC transmission lines is outside the scope of this SAR.

FR data for shunt dynamic reactive devices is required as outline in Reequipments R2, Part 2.3 and Requirement R3, Part 3.3. Static shunt reactive devices, e.g., capacitor bank, is not required. The SER data from a shunt static or dynamic reactive device is required as outlined in Requirement R1, Part 1.1.

Regarding monitoring of IBR unit on collector feeder: Based on comments received, language is revised. Please review and provide feedback.

The term “installed” is replaced with “commercial operation”. Following is added in technical rationale for R1: For IBR Unit in commercial operation prior to the effective date of this standard, SER is data is required, if IBR Unit is capable of recording. Requirement R1, Part 1.2 is revised based on received comments.

R2 states “FR data to determine following electrical quantities” implies that specified quantities could be measured or calculated.

Regarding NERC/Regional Entity as a receipt of information upon a request comment, the standard drafting team reviewed this comment with NERC Staff, and disagrees that alternate mechanisms under the Rules of Procedure (Section 1600 request for information or a NERC Alert) are more appropriate for obtaining time-sensitive disturbance monitoring data under the requirements. Additionally, this language is modeled on approved PRC-002-4.

The data retrievable period is reduced to 20 days in R7. See technical rationale for R7.

The time synchronization accuracy is revised to +/- 1ms. See technical rationale for R6.
The DDR output rate of 60 times per second is required to capture fast response of IBRs during system disturbances and aligns with latest in recording technology.

Section C compliance is updated.

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power's comments are aligned with the MRO NSRF & EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to MRO NSRF and EEI's comments.	
Bret Galbraith - Seminole Electric Cooperative, Inc. - 6	
Answer	
Document Name	
Comment	

1. In the draft Standard PRC-028, Requirement R1.2, a value of 10% is employed. Reviewing significant digits, it's unclear whether this is 10% or 10.0%, etc. Can the NERC STD provide additional guidance?

2. Some IBR units may be procured prior to the enforcement date of the Standard. Due to supply chain issues, PRC-028 R1.2 should be modified to allow an exemption for sites "procured" prior to the FERC approval of this Standard.

3. PRC-028 R1.2 states "and are not capable of recording this data are excluded". Can the SDT provide examples of situations where an IBR is "not capable" of recording this data. This will help provide a basis for discussion with auditors who may assert that "capable" is a vague term, which may lead to unintended disagreements between a utility and audit staff. 4. It's unclear whether NERC intends to modify PRC-028 if traditional non-BES IBR are added to NERC Standards pursuant to parallel analysis ongoing at NERC. Can the NERC SDT comment on how it will deal with IBR that connects at less than 100 kV or is less than 75 MVA, etc., i.e., non-traditional BES sources?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Applicable requirements are revised to state that monitoring of IBR unit connected at a distance greater than or equal to 90% of the longest collector feeder is required. The word "installed" is replaced with "commercial operation" to provide clarity. The "without modification" is added for clarify the exception for IBR units. The standard applies to facilities meeting the Inclusion I4 of the BES definition. As directed by recent FERC Orders (Order No. 901 and IBR Registration Order), the standard would also apply to Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. Refer to technical rationale for more details.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF notes that PRC-002 uses a methodology/threshold for selecting BES buses that require Sequence of Events Recording (SER) and Fault Recording (FR) Data. The NAGF recommends that the Standard Drafting Team consider a similar approach for PRC-028, requiring the TO and RC to identify areas within their regions that are susceptible to disturbances (or high concentration of IBRs) that would benefit from	

monitoring and recording capabilities. This would mitigate the financial impact to the industry as a whole, and target the investment on the areas that need it most.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. Additionally, the recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electrical Institute	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	

Document Name	
Comment	

EEI Comments on PRC-028-1:

Purpose Statement: EEI does not agree that the purpose statement for this Reliability Standard aligns with the intended scope of this project. To address this concern, we offer the following edits in boldface:

To have adequate data available from **a representative number of** inverter-based resources (IBR)**/Facilities** to facilitate **the** analysis **of IBR performance during** Bulk Electric System (BES) Disturbances.

Functional Entities: EEI does not agree with the Functional Entities as listed. We believe that PRC-028 should also include Reliability Coordinators (RC) in this list, noting that the SAR was never intended to require monitoring of IBRs at all locations. Instead, the SDT should develop a criteria for identifying where and when monitoring should be installed and the RC should be the entity that 1) utilizes that criteria to determine where monitoring is needed and 2) notifies owners of their obligations.

Applicability Section: EEI does not agree with the Applicability Section of Section 4.2 because it implies that inverter-based resources are to be included in the BES Definition, Inclusion I2. (See EEI comments for Question 1)

All Requirements: EEI does not agree that this project was intended to monitor all IBRs or IBR Facilities. The SAR states that the intent is to install DDR at some locations, not all locations. The SAR also stated that the requirements were to be balanced against costs which given the magnitude of the proposed requirements, it is difficult to see where costs were adequately balanced.

EEI recommends the SDT develop a criteria that can be used by RCs in assessing where disturbance monitoring should be installed to ensure BES performance is effectively analyzed during disturbances, particularly in areas of high IBR penetration.

Likes 0	
Dislikes 0	
Response	
Thanks for your comments.	

The purpose of the proposed Reliability Standard PRC-028 is revised to clarify that adequate monitoring data is available from IBRs to facilitate analysis of IBR performance during BES disturbances or events. Additionally, the recently published FERC order 901 directs NERC to include technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System. Additionally, the disturbance monitoring data is to be used by planners and operators to validate registered IBR models. The FERC order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs. As such, inclusion of Reliability Coordinator as an applicable Functional Entities is not required. The Inclusion I2 is removed from the Applicability Section.	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
RE: Section C. Compliance: PRC-002-5 and PRC-028-1: Please consider updating section "1.3 Compliance Monitoring and Enforcement Program" with the most recent NERC wording for this section. Please consider removing section "1.4 Additional Compliance Information - None."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Section C, 1.3 is revised and 1.4 is removed.	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	

Constellation does not have any additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Section C, 1.3 is revised and 1.4 is removed.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports the NPCC RSC’s comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NPCC RSC’s comments.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	
Document Name	
Comment	

The requirement to install recording devices to capture IBR performance data through PRC-028-1 should align as closely as possible with the implementation timeframe for the changes made to EOP-004 in Project No. 2023-01 (EOP-004 IBR Event Reporting). This will help ensure that the Events Analysis process has all pertinent data available to make more thorough assessments of IBR-related events.

The SRC believes that referencing just Part (b) of Inclusion I2 in Section 4.2 of the Applicability section of PRC-028-1 is unnecessary, as the language already limits applicability to IBRs and it would be inappropriate to exclude any individual IBRs with a gross individual nameplate rating greater than 20 MVA from the applicability of the standard. The SRC therefore recommends that Section 4.2 of the Applicability section of PRC-028-1 be modified as follows: "The following Elements associated with the inverter-based portion of generating plants/Facilities meeting the criteria set by Inclusion I2 or Inclusion I4 of the BES definition." The SRC has proposed a corresponding modification to the Applicability section of PRC-002-5 in its response to question 1, above. The SRC also recommends that the Applicability section of both standards be aligned with the IBR registration criteria that NERC is in the process of developing under FERC proceeding RD22-4-001.

Based on its review of the draft standards, the SRC is concerned that it is unlikely that transmission system buses in areas of high IBR penetration will be required to have disturbance monitoring and the SRC notes that this monitoring is critical to determining IBR performance on the power system. The Applicability of PRC-028-1 is limited to IBR Facilities, and the methodology in PRC-002-5 Attachment 1 appears to focus on identifying buses with higher fault current levels, which are unlikely to be located in areas with high IBR penetration. The SRC requests that the SDT confirm whether this is the intent of the standards and revise the standards appropriately if this is not the intent.

The SRC notes that PRC-028-1, Requirement 3, Parts 3.1.3, 3.2.3, and 3.3.3 require various forms of trigger settings but do not define associated trigger thresholds. The SRC is concerned that the absence of trigger thresholds will result in inadequate data collection and recommends that the standard be revised to establish default trigger thresholds that apply unless otherwise agreed by the Reliability Coordinator. One possible default threshold would be a requirement that data be captured whenever an IBR changes modes.

Regarding Requirement R7, Part 7.2, the SRC is concerned that allowing 30 calendar days for data to be provided will result in an unacceptably risky delay in the event analysis process. To address this issue, the SRC recommends that Part 7.2 be revised to require that data be provided as soon as possible, but no later than 7 calendar days after a request. PMUs can provide the same data and data storage capabilities this standard requires from DDRs while also providing real-time reporting capability. We ask the project team to affirm PMUs as a means to provide the required data. If so, the performance requirements should not limit any viable option.

The SRC is concerned that Requirement R8 is inadequate to ensure availability of critical data. To address this issue, the SRC recommends that R8 be revised to require regular testing and maintenance of recording equipment and associated infrastructure or to provide that a failure to provide requested data is a violation of PRC-028-1 regardless of the cause of the failure to provide data.

Finally, the SRC recommends that the following revisions be made to PRC-028-1 to more closely align it with table 19 of IEEE 2800:

- Revise Requirement R2, Part 2.1 to require the following additional data points:

o Bus frequency,

o Calculated active and reactive power output, and

o Applicable binary status (e.g., relay out codes).

- Revise Requirement R2, Part 2.2 to require the following additional data points at the plant level:

o Bus frequency,

o Calculated active and reactive power output, and

o Applicable binary status (e.g., relay out codes).

- Revise Requirement R2, Part 2.3 to require bus frequency as an additional data point.

- Revise the total record length in Requirement R3, Parts 3.1.1, 3.2.1, and 3.3.1 from 2 seconds to 5 seconds.

- Revise Requirement R4, Part 4.2 to require the phase current AND the positive sequence current instead of only requiring one or the other.

- Revise Requirement R6, Part 6.2 to require data synchronization accuracy to 1 microsecond at the plant level and 100 microseconds at the unit level.

- Revise the data retention periods in Requirement R7, Part 7.1 to 90 days for SER and FR data and 1 year for DDR data.

- Align the SER data format in Attachment 1 with the format used in IEEE 2800 table 19 and with PRC-002 Attachment 2 by revising it to read as follows:

o Date, Time, Local Time Code, Plant Substation, Device, State, Event type (status changes, synchronization status, configuration change, etc.), Sequence number (for potential overwriting).

o The SRC notes that some breakers may be owned by the generator owner at the station beyond the first station.

- Revise Requirement R7, Part 7.4 to include a reference to IEEE revision C37.111-2013 or later.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The IBR event reporting via EOP-004 under Project No. 2023-01 is achieved by using of SCADA data. Installation of additional equipment is not expected for this task. The installation of disturbance monitoring equipment would be required to comply with the PRC-028. The implementation plan for the PRC-028 accounts for time needed to design, procure, and install necessary equipment to record required data.

Considering other comments received, the Inclusion I2 of the BES definition is removed from the Applicability Section. For now, the standard would apply to facilities meeting the Inclusion I4 of the BES definition. As directed by recent FERC Orders (Order No. 901 and IBR Registration Order), the standard would also apply to Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. Refer to technical rationale for more details.

The intent of PRC-028 is to require monitoring at all IBR facilities. The PRC-002 may not identify transmission buses where IBRs usually connect, however, given that all IBRs will be monitored under the PRC-028, the SDT do not see any gap.

The PRC-028 does not specify trigger levels, as is the case in PRC-002 as well. It is impractical to specify trigger levels that work for all IBRs connected at various locations in all three interconnections.

PMU is one type of dynamic disturbance recorder. The dynamic disturbance recorder is a more generalized term for the purpose and hence used here. PMU could be used to record required quantities.

The 30-calendar time allowed is consist with time allowed in PRC-002.

Requirement R8 in PRC-028 is consistent with similar requirement in PRC-002.

The recording of frequency is specified in R4. The frequency should be same throughout the plant. The recording of quantities as specified should be enough to derive quantities that are not specified, such as, positive-sequence current or voltage, etc.

The SDT received some feedback from OEMs regarding time synchronization accuracy. A better accuracy is always preferred, the accuracy specified in the standard strikes a balance between the latest technology and real world challenges of implementing it. Some of these issues were likely not considered by or known to WG developing IEEE Std 2800.

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	

PNMR is in support of EEI's commnents for question 5.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. See response to IRC SRC's comments	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation does not have any additional comments.	

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments.	

Israel Perez (Proxy for Thomas Johnson) – Salt River Project

Questions:

1. Yes

   Response: Thanks for your support.

2. Yes

   Response: Thanks for your support.

3. No

   PRC-028 -The data sampling rates seem excessive and are a significant increase from the requirements in PRC-002. These sampling rates will prevent the use of protective relaying to satisfy the standard, which will increase cost burden

   Response: Thanks for your comment. The IBRs are fast acting devices and hence, high sampling rate compared to one specified in PRC-002 is required. However, considering comments submitted by the industry, minimum recording rate for FR data is reduced to 64 samples per cycle from initially proposed 128 samples per cycle.

4. Yes

   Response: Thanks for your support.

5. Additional Comments

   PRC-028 - If the point of 4.2.5 is to monitor the individual inverter performance prior to being summed into a collector system, I would consider mandating the last IBR on each feeder is monitored, rather than one of the IBR units in the last 10% of each feeder.

Response: Thanks for your comment. The SDT agrees that monitoring the last IBR unit on each collector feeder would be ideal. However, realizing that in some cases, monitoring last IBR unit may not be feasible, and hence monitoring an IBR unit connected to "last 10% of collector feeder length" allows for some flexibility. Note that considering other comments, the language is revised to "at least one IBR unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus".

Reminder

Standards Announcement

Project 2021-04 Modifications to PRC-002- Phase II

Initial Ballots and Non-binding Polls Open through September 14, 2023

Now Available

Initial ballots and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels for **Project 2021-04 Modifications to PRC-002- Phase II** are open through **8 p.m. Eastern, Thursday, September 14, 2023** for the following standards and implementation plan:

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

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

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 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 2021-04 Modifications to PRC-002 observer list” 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

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Open through September 14, 2023
Ballot Pools Forming through August 30, 2023

Now Available

A 45-day formal comment period for **Project 2021-04 Modifications to PRC-002- Phase II** is open through **8 p.m. Eastern, Thursday, September 14, 2023** for the following standards and implementation plan:

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

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact **ballotadmin@nerc.net** to assist with the removal of any duplicate registrations.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Wednesday, August 30, 2023.** 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 the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 5 - 14, 2023**.

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 2021-04 Modifications to PRC-002 observer list” in the Description Box.

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Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 IN 1 ST
Voting Start Date: 9/5/2023 12:01:00 AM
Voting End Date: 9/14/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 241
Total Ballot Pool: 274
Quorum: 87.96
Quorum Established Date: 9/14/2023 12:48:51 PM
Weighted Segment Value: 61.44

Actions

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	74	1	36	0.563	28	0.438	0	4	6
Segment: 2	8	0.6	5	0.5	1	0.1	0	0	2
Segment: 3	60	1	30	0.577	22	0.423	0	3	5
Segment: 4	14	0.6	3	0.3	3	0.3	0	3	5
Segment: 5	68	1	28	0.491	29	0.509	0	3	8
Segment: 6	43	1	20	0.571	15	0.429	0	3	5
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	0	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	0	1
Totals:	274	5.7	127	3.502	98	2.198	0	16	33

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	Third-Party Comments
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted

3	Lincoln Electric System	Sam Christensen		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A

5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch	Karen Frank	Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	National Grid USA	Robin Berry		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A

10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
6	Manitoba Hydro	Kelly Bertholet		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	BC Hydro and Power Authority	Alan Xu		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
3	AEP	Kent Feliks		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
6	AEP	Justin Kuehne		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A

4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted

1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
5	Santee Cooper	Don Cribb		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Brandon Smith		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Stephanie Kenny		None	N/A
					Third-Party

6	Muscatine Power and Water	Nicholas Burns		Negative	Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Negative	Comments Submitted
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
1	Hydro One Networks, Inc.	Alain Mukama	Ijad Dewan	Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A

6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
2	California ISO	Darcy O'Connell	Val Neiberger	Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		Affirmative	N/A
5	JEA	John Babik		Negative	Third-Party Comments
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A

5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Decatur Energy Center LLC	Megan Melham		None	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II Implementation Plan IN 1 OT
Voting Start Date: 9/5/2023 12:01:00 AM
Voting End Date: 9/14/2023 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 239
Total Ballot Pool: 274
Quorum: 87.23
Quorum Established Date: 9/14/2023 12:49:30 PM
Weighted Segment Value: 42.96

Actions

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	74	1	29	0.46	34	0.54	0	5	6
Segment: 2	7	0.5	1	0.1	4	0.4	0	0	2
Segment: 3	60	1	20	0.392	31	0.608	0	4	5
Segment: 4	14	0.6	2	0.2	4	0.4	0	3	5
Segment: 5	68	1	21	0.382	34	0.618	0	4	9
Segment: 6	44	1	17	0.486	18	0.514	0	3	6
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	0	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.3	3	0.3	0	0	0	2	1
Totals:	274	5.4	93	2.32	125	3.08	0	21	35

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	Third-Party Comments
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted

3	Lincoln Electric System	Sam Christensen		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
2	ISO New England, Inc.	John Pearson		Negative	Third-Party Comments
6	Entergy	Julie Hall		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A

3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch	Karen Frank	Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	National Grid USA	Robin Berry		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
6	Manitoba Hydro	Kelly Bertholet		Affirmative	N/A

5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	BC Hydro and Power Authority	Alan Xu		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
3	AEP	Kent Feliks		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
6	AEP	Justin Kuehne		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael	Negative	Comments

			Johnson		Submitted
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments

2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
5	Santee Cooper	Don Cribb		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Brandon Smith		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party

					Comments
6	Edison International - Southern California Edison Company	Stephanie Kenny		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Negative	Comments Submitted
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Alain Mukama	Ijad Dewan	Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A

5	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
5	Pine Gate Renewables	Michiko Sell		Affirmative	N/A
5	JEA	John Babik		Negative	Third-Party Comments

1	Hydro-Quebec (HQ)	Nicolas Turcotte		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	Salt River Project	Sarah Blankenship	Israel Perez	Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Decatur Energy Center LLC	Megan Melham		None	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A

3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		None	N/A
6	Great River Energy	Brian Meloy		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 | Non-Binding Poll IN 1 NB
Voting Start Date: 9/5/2023 12:01:00 AM
Voting End Date: 9/14/2023 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 229
Total Ballot Pool: 266
Quorum: 86.09
Quorum Established Date: 9/14/2023 1:32:09 PM
Weighted Segment Value: 54.45

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	26	0.5	26	0.5	12	7
Segment: 2	7	0.5	4	0.4	1	0.1	0	2
Segment: 3	58	1	25	0.556	20	0.444	8	5
Segment: 4	14	0.7	3	0.3	4	0.4	2	5
Segment: 5	67	1	25	0.532	22	0.468	10	10
Segment: 6	42	1	17	0.548	14	0.452	5	6
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	0

Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	6	0.4	4	0.4	0	0	1	1
Totals:	266	5.6	104	3.236	87	2.364	38	37

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Abstain	N/A

1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments

					Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch	Karen Frank	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	National Grid USA	Robin Berry		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted

1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	BC Hydro and Power Authority	Alan Xu		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
3	AEP	Kent Feliks		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
6	AEP	Justin Kuehne		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
	Con Ed - Consolidated Edison Co. of New				Comments

5	York	Helen Wang		Negative	Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A

5	Santee Cooper	Don Cribb		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Brandon Smith		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Negative	Comments Submitted
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
1	Hydro One Networks, Inc.	Alain Mukama	Ijad Dewan	Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A

6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Abstain	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A

3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		Affirmative	N/A
5	JEA	John Babik		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted

5	Decatur Energy Center LLC	Megan Melham		None	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll IN 1 NB
Voting Start Date: 9/5/2023 12:01:00 AM
Voting End Date: 9/14/2023 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 223
Total Ballot Pool: 261
Quorum: 85.44
Quorum Established Date: 9/14/2023 1:37:45 PM
Weighted Segment Value: 28.07

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	69	1	11	0.25	33	0.75	16	9
Segment: 2	7	0.5	3	0.3	2	0.2	0	2
Segment: 3	57	1	10	0.238	32	0.762	10	5
Segment: 4	14	0.6	1	0.1	5	0.5	3	5
Segment: 5	66	1	11	0.262	31	0.738	15	9
Segment: 6	41	1	8	0.286	20	0.714	7	6
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	0

Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	6	0.4	4	0.4	0	0	1	1
Totals:	261	5.5	48	1.836	123	3.664	52	38

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A

1	Tennessee Valley Authority	David Plumb		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments

					Submitted
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Abstain	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch	Karen Frank	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	National Grid USA	Robin Berry		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted

1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	BC Hydro and Power Authority	Alan Xu		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
3	AEP	Kent Feliks		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
6	AEP	Justin Kuehne		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Comments Submitted

1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A

5	Santee Cooper	Don Cribb		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Brandon Smith		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Olivia Olson		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Negative	Comments Submitted

6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
1	Hydro One Networks, Inc.	Alain Mukama	Ijad Dewan	Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Abstain	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A

1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		Negative	Comments Submitted
5	JEA	John Babik		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
					Comments

1	Salt River Project	Sarah Blankenship	Israel Perez	Negative	Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	JEA	Marilyn Williams		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		None	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		None	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted

Project 2021-04 Modifications to Disturbance Monitoring and Reporting Requirements

Action

- Approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2021-04:
  - Additional formal comment and ballot period (s) reduced from 45 days to as little as 15 days, with ballot conducted during the last 10 days of the comment period. (Sections 4.9 and 4.12)
  - Final ballot reduced from 10 days to 5 calendar days. (Section 4.9)

Background

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

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

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

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

NERC Standard Processes Manual Section 16.0 Waiver provides as follows:

> The SC may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:
>
> - In response to a national emergency declared by the United States or Canadian government that involves the reliability of the Bulk Electric System (BES) or cyber attack on the BES;
> - Where necessary to meet regulatory deadlines;

- Where necessary to meet deadlines imposed by the NERC Board of Trustees; or
- Where the SC determines that a modification to a proposed Reliability Standard or its requirement(s), a modification to a defined term, a modification to an Interpretation, or a modification to a variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.

FERC Order 901 directs the development of new or modified reliability standards, including new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. This set of directives from the report comprises the first of three sets of Standards Projects that must be completed and filed with FERC. This first set (disturbance monitoring data sharing and post-event performance validation and correction of IBR performance) must be filed with FERC by November 4, 2024.

NERC Standards Development has identified three active projects (2020-02, 2021-04, and 2023-02) that are directly impacted by these associated FERC directives. Project 2021-04 DT leadership and NERC staff request that the SC approve a waiver for certain provisions of the SPM regarding the length of comment periods and ballots in order to meet the November 2024 development deadline for 2021-04 as established by FERC.

Summary
Project 2021-04 DT leadership and NERC staff recommend that the SC shorten additional formal comment and ballot period(s) from 45 days to as few as 15 days. NERC staff is only recommending this reduction for additional comment and ballot period(s) because initial ballot was completed August 1 – September 14, 2023. In addition, Project 2021-04 DT leadership and NERC staff recommend that the final ballot be shortened from 10 days to 5 days.

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021
Modified SAR to create a new Standard (PRC-028-1)	04/19/2023

Anticipated Actions	Date
45-day formal comment period with ballot	08/01/2023 – 09/14/2023
25-day formal or informal comment period with additional ballot	03/18/2024 – 04/11/2024
10-day final ballot	05/28/2024 – 06/06/2024
Board adoption	11/04/2024

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

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

Term(s):

The term Inverter-Based Resource (IBR) refers to the proposed definition being developed under the Project 2020-06 Verifications of Models and Data for Generators.

As of this posting, this definition is:

Inverter-Based Resource: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-5
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
   - **4.2. Facilities:** BES Elements, excluding Inverter-Based Resources.[1]
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

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

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

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

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

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

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES

[1] Disturbance monitoring and reporting requirements for Inverter-Based Resources are addressed in PRC-028.

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

buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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

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

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

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

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

3.2.2. Transmission Lines.

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

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

4.1. A single record or multiple records that include:

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

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

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1)

documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

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

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

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

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

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

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

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

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

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

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

5.2.1. One BES Element; and

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

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

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

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

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

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

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

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

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of the Reliability Standard PRC-002-2[3] and is not capable of continuous recording, triggered records

[3] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	>0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.

11.3. SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. FR and DDR data will be provided either in CSV format or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, for five calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of

Requirements R2, R3, R4, R8, R9, R10, R11, and R12, for three calendar years.

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	20 calendar days, but less than or equal to 30 calendar days.	
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent, but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent, but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent, but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent, but less than 100 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by 30 calendar days or less.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent, but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 30 calendar	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent, but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 60 calendar days and less	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 90 calendar days.

			OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.

R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent, but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent, but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent, but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60

			than 100 percent of the total recording properties as specified in Requirement R9.	equal to 80 percent of the total recording properties as specified in Requirement R9.	than or equal to 70 percent of the total recording properties as specified in Requirement R9.	percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent, but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent, but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent, but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority.

			extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days

			calendar days after discovery of the failure.	days after discovery of the failure.	calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months, but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months, but less	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

					than or equal to 12 months.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-5: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-5: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005.

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-2. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC Oder Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14, 2023	Effective Date	April 1, 2024
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored Bulk Electric System (BES) buses for SER and FR data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns. Refer to section 4.2 Facilities for exclusion.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three-phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three-phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three-phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete, and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more, but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three-phase short circuit MVA of the newly identified BES bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

<u>If the list has more than 11 BES buses:</u> SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three-phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other Disturbance Monitoring Equipment (DME) devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[4]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[4] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc., is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021
Modified SAR to create a new Standard (PRC-028-1)	04/19/2023

Anticipated Actions	Date
45-day formal comment period with ballot	08/01/2023 – 09/14/2023 ~~06/09/2022 – 07/15/2022~~
~~45~~25-day formal or informal comment period with additional ballot	03/18/2024 – 04/11/2024 ~~09/26/2022 – 11/09/2022~~
10-day final ballot	05/28/2024 – 06/06/2024 ~~12/07/2022 – 12/16/2022~~
Board adoption	11/04/2024 ~~02/09/2023 – 03/15/2023~~

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):

~~N/A.~~ The term Inverter-Based Resource (IBR) refers to the proposed definition being developed under the Project 2020-06 Verifications of Models and Data for Generators.

As of this posting, this definition is:

Inverter-Based Resource: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-~~5~~4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Owner

   4.1.3. Generator Owner

   4.2. Facilities: BES Elements, excluding ~~inverter-based~~Inverter-Based Resources~~portions of generating plants/Facilities meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition~~.[1]
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-~~5~~4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[2] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-~~5~~4, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that

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[1] Disturbance monitoring and reporting requirements for ~~inverter-based resources~~Inverter-Based Resources are addressed in PRC-028.

[2] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns directly connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Phase-to-neutral voltage for each phase of each specified BES bus.

3.2. Each phase current and the residual or neutral current for the following BES Elements:

3.2.1. Transformers that have a low-side operating voltage of 100 kV or above.

3.2.2. Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2. A minimum recording rate of 16 samples per cycle.

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1. Synchronous machine based generating resource(s) with:

5.1.1.1. Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2. Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2. Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3. Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5. Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2. Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1. One BES Element; and

5.2.2. One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3. Notify all owners of identified BES Elements, within 90 calendar days of completion of Part 5.1, that their respective BES Elements require DDR data.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability

Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. One phase-to-neutral or positive sequence voltage.

6.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of the Reliability Standard PRC-002-2[3] and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	>0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES

[3] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.

11.3. SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. FR and DDR data will be provided in either in CSV format or electronic files that are formatted in conformance with C37.111, ~~(~~IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1)

dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: “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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, for five calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12, for three calendar years.

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non- compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Violation Investigation~~
- ~~Self-Reporting~~
- ~~Complaints~~

~~**1.4. Additional Compliance Information**~~

~~None.~~

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	20 calendar days, but less than or equal to 30 calendar days.	
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent, but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent, but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent, but less than 100 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by 30 calendar days or less.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent, but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 30 calendar	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent, but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 60 calendar days and less	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 90 calendar days.

			OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of applicable~~monitored~~ BES Elements and the number of specified electrical	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable~~monitored~~ BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable~~monitored~~ BES Elements and the number of specified electrical	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable~~monitored~~ BES Elements and the number of specified electrical quantities for each applicable BES Element.

			quantities for each applicable BES Element.		quantities for each applicable BES Element.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of ~~monitored~~applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of ~~monitored~~applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of ~~monitored~~applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of ~~monitored~~applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent, but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent, but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent, but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent, but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent, but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent, but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide the requested data more than 60

			less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to

			Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	the Regional Entity more than 120 calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part

				and was late by less than or equal to 6 months.	5.4 and was late by greater than 6 months but less than or equal to 12 months.	5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-5~~4~~: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-5~~4~~: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005.

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-2~~4~~. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC Oder Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14, 2023	Effective Date	April 1, 2024
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored Bulk Electric System (BES) buses for SER and FR data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of ~~Bulk Electric System (~~BES~~)~~ buses that it owns. Refer to section 4.2 Facilities for exclusion.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three-phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three-phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three-phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete, and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three-phase short circuit MVA of the newly identified BES bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three-phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other Disturbance Monitoring Equipment (DME) devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[4]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[4] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021
Modified SAR to create a new Standard (PRC-028-1)	04/19/2023

Anticipated Actions	Date
45-day formal comment period with ballot	08/01/2023 – 09/14/2023 ~~06/09/2022 – 07/15/2022~~
~~45~~25-day formal or informal comment period with additional ballot	03/18/2024 – 04/11/2024 ~~09/26/2022 – 11/09/2022~~
10-day final ballot	05/28/2024 – 06/06/2024 ~~12/07/2022 – 12/16/2022~~
Board adoption	11/04/2024 ~~02/09/2023 – 03/15/2023~~

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):

~~N/A.~~ The term Inverter-Based Resource (IBR) refers to the proposed definition being developed under the Project 2020-06 Verifications of Models and Data for Generators.

As of this posting, this definition is:

Inverter-Based Resource: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-5~~4~~
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
   - **4.2.** **Facilities:** BES Elements, excluding Inverter-Based Resources.[1]
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-5~~4~~, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[2] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-5~~4~~, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES

[1] Disturbance monitoring and reporting requirements for Inverter-Based Resources are addressed in PRC-028.

[2] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns directly connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Phase-to-neutral voltage for each phase of each specified BES bus.

3.2. Each phase current and the residual or neutral current for the following BES Elements:

3.2.1. Transformers that have a low-side operating voltage of 100 kV or above.

3.2.2. Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2. A minimum recording rate of 16 samples per cycle.

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1)

documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1. Synchronous machine based ~~G~~generating resource(s) with:

5.1.1.1. Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2. Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2. Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3. Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5. Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2. Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1. One BES Element; and

5.2.2. One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3. Notify all owners of identified BES Elements, within 90 calendar days of completion of Part 5.1, that their respective BES Elements require DDR data.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to~~:~~ letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. One phase-to-neutral or positive sequence voltage.

6.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3. Real Power and Reactive Power flows expressed on a three-~~-~~-phase basis corresponding to all circuits where current measurements are required.

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3. Real Power and Reactive Power flows expressed on a three-~~-~~-phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of the Reliability Standard PRC-002-2[3] and is not capable of continuous recording, triggered records

[3] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	>0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.

11.3. SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. FR and DDR data will be provided either in CSV format or in electronic files that are formatted in conformance with C37.111, ~~(~~IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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. ~~Data~~Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1,~~ Measure M1~~ for five calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, ~~Measure M5~~ for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, ~~Measure M6 ~~for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, ~~Measure M7~~ for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of

~~requested data provided as per~~ Requirements R2, R3, R4, R8, R9, R10, R11, and R12, ~~Measures M2, M3, M4, M8, M9, M10, M11, and M12~~ for three calendar years.

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, ~~Measure 13~~ for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-~~-~~compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Violation Investigation~~
- ~~Self-Reporting~~
- ~~Complaints~~

~~**1.4. Additional Compliance Information**~~

~~None.~~

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	20 calendar days, but less than or equal to 30 calendar days.	
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent, but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent, but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters~~properties~~ as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters~~properties~~ as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters~~properties~~ as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters~~properties~~ as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent, but less than 100 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent, but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 30 calendar	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent, but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 60	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but

			was late by 30 calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	calendar days and less than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	was late by greater than 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical	The Transmission Owner ~~failed to~~ had~~ve~~ DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical

			quantities for each applicable BES Element ~~for all applicable BES Elements~~.	applicable BES Element ~~for all applicable BES Elements~~.	quantities for each applicable BES Element ~~for all applicable BES Elements~~.	quantities for each applicable BES Element.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is -the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element~~for all applicable BES Elements~~.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element ~~for all applicable BES Elements~~.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element ~~for all applicable BES Elements~~.	The Generator Owner ~~failed to~~ had~~ve~~ DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent, but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent, but less than or equal to 80 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent, but less than or equal to 70 percent of the BES Elements they own as	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	determined in Requirement R5.	determined in Requirement R5.	
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent, but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent, but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent, but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to

			the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	provide the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a

			provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part

				and was late by less than or equal to 6 months.	during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-~~5~~4: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-~~5~~4: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005.

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-24. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC Oder Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14, 2023	Effective Date	April 1, 2024
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored Bulk Electric System (BES) buses for ~~sequence of events recording (~~SER~~)~~ and ~~Fault recording (~~FR~~)~~ data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns. Refer to section 4.2 Facilities for exclusion.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three~~-~~-phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three~~-~~-phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three~~-~~-phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete, and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three~~-~~-phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three~~-~~-phase short circuit MVA of the newly identified BES bus is within 15% of the three~~-~~-phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three-~~-~~phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other Disturbance Monitoring Equipment (DME) devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[4]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[4] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021
Modified SAR to create a new Standard (PRC-028-1)	04/19/2023

Anticipated Actions	Date
45-day formal comment period with ballot	08/01/2023 – 09/14/2023
25-day formal or informal comment period with additional ballot	03/18/2024 – 04/11/2024
10-day final ballot	05/28/2024 – 06/06/2024
Board adoption	11/04/2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

The terms Inverter-Based Resource (IBR) and IBR unit refer to the proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators.

As of this posting, these definitions are:

Inverter-Based Resource: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell.

IBR Unit: An individual device that uses a power electronic interface, such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connects at a single point on the collector system; or a grouping of multiple devices that uses a power electronic interface(s), such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connect together at a single point on the collector system.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
2. **Number:** PRC-028-1
3. **Purpose:** To have adequate data available from Inverter-Based Resources (IBR) to facilitate analysis of IBR performance during Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Owner that owns equipment as identified in section 4.2
     - **4.1.2.** Generator Owner that owns equipment as identified in section 4.2
   - **4.2. Facilities:** The Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner and Generator Owner shall have sequence of event recording (SER) data for the following Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- **1.1.** Circuit breaker position (open/close) for circuit breakers associated with the main power transformer(s)[1], collector bus(es), and shunt static or dynamic reactive device(s).
- **1.2.** For IBR Units in commercial operation after [the effective date of this standard]: at least one IBR Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% of the longest collector feeder. The following data shall be recorded when triggered by ride-through operation or tripping of an IBR Unit.
  - **1.2.1.** All fault codes.
  - **1.2.2.** All fault alarms.
  - **1.2.3.** High and low voltage ride-through mode status.
  - **1.2.4.** High and low frequency ride-through mode status.

[1] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.

1.3. For IBR Units in commercial operation prior to [the effective date of this standard]: at least one IBR Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% of the longest collector feeder. The following data shall be recorded, if capable of recording, when triggered by ride-through operation or tripping of an IBR Unit.

1.3.1. All fault codes.

1.3.2. All fault alarms.

1.3.3. High and low voltage ride-through mode status.

1.3.4. High and low frequency ride-through mode status.

M1. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1. Evidence may include, but is not limited to: (1) actual data recordings; or (2) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R2. Each Transmission Owner and Generator Owner shall have triggered fault recording (FR) data to determine the following electrical quantities for Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. High-side of the main power transformer FR data:

2.1.1. Phase-to-neutral voltage for each phase.

2.1.2. Each phase current and the residual or neutral current.

2.1.3. Real and reactive power.

2.2. IBR Unit FR data from at least one IBR Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% of the longest collector feeder:

2.2.1. Each AC phase-to-neutral or phase-to-phase voltage, as applicable, at IBR Unit terminals or on high-side of the IBR Unit transformer.

2.2.2. Each AC phase current and the residual or neutral current, as applicable, on IBR Unit terminals or on high-side of the IBR Unit transformer.

2.3. Shunt dynamic reactive device data:

2.3.1. Phase-to-neutral voltage for each phase.

2.3.2. Each phase current and the residual or neutral current.

2.3.3. Real and reactive power output.

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R2. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R2 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. High-side of the main power transformer FR data

3.1.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.1.2. A minimum recording rate of 64 samples per cycle.

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

3.2. IBR Unit level data

3.2.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2 seconds for the same trigger point.

3.2.2. A minimum recording rate of 64 samples per cycle).

3.2.3. Trigger settings for at least the following:

3.2.3.1. AC Phase overvoltage and undervoltage.

3.2.3.2. Overfrequency and underfrequency.

3.3. Shunt dynamic reactive device FR data

3.3.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.3.2. A minimum recording rate of 64 samples per cycle.

3.3.3. Trigger settings for at least the following:

3.3.3.1. Neutral (residual) overcurrent.

3.3.3.2. AC phase overvoltage and undervoltage.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R3. Evidence may include, but is not limited to: (1) actual data recordings or derivations, or (2) documents describing the device specification and device configuration or settings.

R4. Each Generator Owner and Transmission Owner shall have continuous dynamic disturbance recording (DDR) data and storage to determine the following electrical quantities for each main power transformer(s) it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. One phase-to-neutral or positive sequence voltage on high-side of the main power transformer(s).

4.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R4, Part 4.1, or the positive sequence current.

4.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to each main power transformer(s) where current measurements are required.

4.4. Frequency of any one of the voltage(s) in Requirement R4, Part 4.1.

M4. The Generator Owner or Transmission Owner has evidence (electronic or hard copy) of continuous DDR data recording and storage to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (3) station drawings.

R5. Each Transmission Owner and Generator Owner responsible for DDR data for the electrical quantities identified in Requirement R4 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Input sampling rate of at least 960 samples per second.

5.2. Output recording rate of electrical quantities of at least 60 times per second.

M5. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R5. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R5, Part 5.1; R5, Part 5.2); or (2) actual data recordings (R5, Part 5.2).

R6. Each Transmission Owner and Generator Owner shall time synchronize all SER, FR, and DDR data to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

6.2. Synchronized device clock accuracy within ± 1 milliseconds of UTC.

M6. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R7. Each Transmission Owner and Generator Owner shall provide, upon request, all SER, FR, and DDR data to its Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within 30 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII[2] Comma Separated Value (CSV) format following Attachment 1.

7.4. FR and DDR data shall be provided either in CSV format or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

7.5. Data files shall be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M7. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R7. Evidence may include, but is not limited to: (1) actual data recordings; (2) dated transmittals to the requesting entity with formatted records; or (3) documents describing data storage capability, device specification, configuration, or settings.

R8. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR, or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M8. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R8. Evidence may include, but is not limited to: (1) dated reports of the discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated Corrective Action Plan transmittals to the Regional Entity and evidence of Corrective Action Plan implementation.

R9. Each Transmission Owner and Generator Owner of an applicable facility as specified in section A.4.2 that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance shall develop, maintain, and implement a Corrective Action Plan to provide the required capability. For each Corrective Action Plan, the Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

[2] American Standard Code for Information Exchange

9.1. Identify corrective actions and a timetable for completion.

9.2. Specify the circumstances causing the delay for fully or partially implementing Requirements R1 through R7 and explain how those circumstances are beyond the control of the responsible entity.

9.3. Identify revisions to the selected actions in Part 9.1, if any.

9.4. Identify updates to the timetable for implementing the selected actions in Part 9.1, if any.

9.5. Submit the Corrective Action Plan, and any revisions, to the Regional Entity, with a request to extend the time provided for compliance.

M9. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R9. Evidence may include, but is not limited to, documentation noting the date the Corrective Action Plan was developed or revised, documentation noting the date the Corrective Action Plan was submitted to the Regional Entity with request to extend the time provided for compliance, and evidence of Corrective Action Plan implementation.

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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner and Generator Owner shall retain evidence, as per Requirements R1 through R8, for three calendar years.

If a Transmission Owner or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the Elements (circuit breaker(s) or IBR Units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the Elements (circuit breaker(s) or IBR Units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent but less than or equal to 70 percent of the Elements (circuit breaker(s) or IBR Units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the Elements (circuit breaker(s) or IBR Units) identified in Section 4.2 Facilities.
R2	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical

			quantities for each Element.	electrical quantities for each Element.	quantities for each Element.	quantities for each Element.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

R5	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.
R6	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.
R7	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as

			directed by Requirement R7, Part 7.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	directed by Requirement R7, Part 7.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	directed by Requirement R7, Part 7.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	directed by Requirement R7, Part 7.2 failed to provide the requested data more than 60 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided less than or equal to 70 percent of the data in the proper data format.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 120

			calendar days after discovery of the failure.	days after discovery of the failure.	calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan and submitted it to the Regional Entity, but failed to submit any revisions to the Regional Entity as required by Requirement R9.	The Transmission Owner or Generator Owner developed and implemented a Corrective Action Plan and submitted it to the Regional Entity as required by Requirement R9, but failed to maintain it.	The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan, but failed to submit it to the Regional Entity as required by Requirement R9.	The Transmission Owner or Generator Owner failed to develop, maintain, or implement a Corrective Action Plan as required by Requirement R9.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-028-1: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011: IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

IEEE Std 2800-2022: IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.

Multiple Solar PV Disturbances in CAISO, Joint NERC and WECC Staff Report, April 2022.

NERC Reliability Standard PRC-002-5.

Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021, Joint NERC and Texas RE Event Report, September 2021.

Odessa Disturbance, Texas Event: June 4, 2022, Joint NERC and Texas RE Event Report, December 2022.

Version History

Version	Date	Action	Change Tracking
0	TBD	Adopted by NERC Board of Trustees	New

Attachment 1

Sequence of Events Recording (SER) Data Format

(Requirement R7, Part 7.3)

Date, Time, Local Time Code, Plant Name, Device[3], State[4]

08/27/23, 23:58:57.110, -5, Plant name 1, Breaker 1, Close

08/27/23, 23:58:57.082, -5, Plant name 2, Breaker 2, Close

08/27/23, 23:58:47.217, -5, Plant name 1, IBR Unit 1, Open

08/27/23, 23:58:47.214, -5, Plant name 2, IBR Unit 2, Open

08/27/23, 23:58:47.217, -5, Plant name 1, IBR Unit 1, undervoltage ride-through mode

08/27/23, 23:58:47.214, -5, Plant name 2, IBR Unit 2, dc overcurrent trip

[3] Device name may include specific names of breakers or IBR Units as appropriate.

[4] Breaker status and any other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc., is acceptable. For IBR Unit level data, fault codes, alarms, change in operating mode etc., are also acceptable.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021
Modified SAR to create a new Standard (PRC-028-1)	04/19/2023

Anticipated Actions	Date
45-day formal comment period with ballot	08/01/2023 – 09/14/2023
2~~4~~5-day formal or informal comment period with additional ballot	03/18/2024 – 04/11/2024
10-day final ballot	05/28/2024 – 06/06/2024
Board adoption	11/04/2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

~~N/A.~~The terms Inverter-Based Resource (IBR) and IBR unit refers to the proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators.

As of this posting, these definitions are:

Inverter-Based Resource: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell.

IBR Unit: An individual device that uses a power electronic interface, such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connects at a single point on the collector system; or a grouping of multiple devices that uses a power electronic interface(s), such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connect together at a single point on the collector system.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

2. **Number:** PRC-028-1

3. **Purpose:** To have adequate data available from ~~inverter-based resources~~ Inverter-Based Resources (IBR) to facilitate analysis of IBR performance during ~~of~~ Bulk Electric System (BES) Disturbances.

4. **Applicability:**

 4.1. Functional Entities:

 4.1.1. Transmission Owner that owns equipment as identified in section 4.2

 4.1.2. Generator Owner that owns equipment as identified in section 4.2

 ~~**4.2.**~~ **Facilities:** The ~~following~~ Elements associated with (1) BES Inverter-Based Resources; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV~~BES generating plants (inverter-based portion of generating plant/Facility meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition.):~~

 ~~**4.3.** Circuit breaker(s).~~

 ~~**4.4.** Main power transformer(s)[1].~~

 ~~**4.5.** Collector bus.~~

 ~~**4.6.** Shunt static or dynamic reactive device(s).~~

 ~~**4.7.**~~**4.2.** ~~At least one IBR unit[2] connected to last 10% of each collector feeder length (i.e., furthest from the collector bus).~~

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner and Generator Owner shall have sequence of event recording (SER) data for the following Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~[1] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.~~

~~[2] IBR unit includes the inverter, converter, wind turbine generator, or high voltage direct current converter connecting generating resource to alternating current Transmission network.~~

1.1. Circuit breaker position (open/close) for circuit breakers associated with the main power transformer(s)[3], collector bus(es), and shunt static or dynamic reactive device(s) ~~Elements identified in section 4.2~~.

1.2. For IBR Units in commercial operation after [the effective date of this standard]: ~~A~~at least one IBR ~~u~~Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% ~~to last 10%~~ of ~~each~~the longest collector feeder ~~length~~. ~~IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded.~~ The following data shall be recorded when triggered by ride-through operation or tripping of an IBR Unit.

1.2.1. All fault codes.

~~**1.2.2.**~~ All fault alarms.

~~**1.2.3.**~~**1.2.2.** ~~Change of operating mode.~~

~~**1.2.4.**~~**1.2.3.** High and low voltage ride-through mode status.

~~**1.2.5.**~~ High and low frequency ride-through mode status.

1.2.4. ~~Control system command values, reference values, and feedback~~

~~**1.3.** signals.~~

1.3. For IBR Units in commercial operation prior to [the effective date of this standard]: at least one IBR Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% of the longest collector feeder. The following data shall be recorded, if capable of recording, when triggered by ride-through operation or tripping of an IBR Unit.

1.3.1. All fault codes.

1.3.2. All fault alarms.

1.3.3. High and low voltage ride-through mode status.

1.3.4. High and low frequency ride-through mode status.

M1. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1. Evidence may include, but is not limited to: (1) actual data recordings; or (2) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R2. Each Transmission Owner and Generator Owner shall have triggered fault recording (FR) data to determine the following electrical quantities for Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

[3] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.

2.1. High-side of the main power transformer FR data:

2.1.1. Phase-to-neutral voltage for each phase.

2.1.2. Each phase current and the residual or neutral current.

2.1.3. Real and reactive power.

2.2. IBR ~~u~~Unit FR data from at least one IBR ~~u~~Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% ~~to last 10%~~ of ~~each~~the longest collector feeder~~ length~~:

2.2.1. Each AC phase-to-neutral or phase-to-phase voltage, as applicable, at IBR ~~u~~Unit terminals or on high-side of the IBR ~~u~~Unit transformer.

~~**2.2.2.**~~ Each AC phase current and the residual or neutral current, as applicable, on IBR ~~u~~Unit terminals or on high-side of the IBR ~~u~~Unit transformer.

~~**2.2.3.**~~**2.2.2.** ~~DC bus current and voltage. IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded.~~

2.3. Shunt ~~D~~dynamic reactive device data:

2.3.1. Phase-to-neutral voltage for each phase.

2.3.2. Each phase current and the residual or neutral current.

2.3.3. Real and reactive power output.

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R2. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R2 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. High-side of the main power transformer FR data

3.1.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.1.2. A minimum recording rate of 64~~128~~ samples per cycle.

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

3.2. IBR ~~u~~Unit level data

3.2.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2 seconds for the same trigger point.

3.2.2. A minimum recording rate of ~~128~~64 samples per cycle).

3.2.3. Trigger settings for at least the following:

3.2.3.1. AC Phase overvoltage and undervoltage.

~~**3.2.3.2.** DC overvoltage, DC overcurrent, and DC reverse current.~~

~~**3.2.3.3.**~~**3.2.3.2.** Overfrequency and underfrequency.

3.3. Shunt ~~D~~dynamic reactive device FR data

3.3.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.3.2. A minimum recording rate of 64~~128~~ samples per cycle.

3.3.3. Trigger settings for at least the following:

3.3.3.1. Neutral (residual) overcurrent.

3.3.3.2. AC phase overvoltage and undervoltage.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R3. Evidence may include, but is not limited to: (1) actual data recordings or derivations, or (2) documents describing the device specification and device configuration or settings.

R4. Each Generator Owner and Transmission Owner shall have continuous dynamic disturbance recording (DDR) data and storage to determine the following electrical quantities for each main power transformer(s) it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. One phase-to-neutral or positive sequence voltage on high-side of the main power transformer(s).

4.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R4, Part 4.1, or the positive sequence current.

4.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to each main power transformer(s) where current measurements are required.

4.4. Frequency of any one of the voltage(s) in Requirement R4, Part 4.1.

M4. The Generator Owner or Transmission Owner has evidence (electronic or hard copy) of continuous DDR data recording and storage to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (3) station drawings.

R5. Each Transmission Owner and Generator Owner responsible for DDR data for the electrical quantities identified in Requirement R4 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Input sampling rate of at least 960 samples per second.

5.2. Output recording rate of electrical quantities of at least 60 times per second.

M5. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R5. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R5, Part 5.1; R5, Part 5.2); or (2) actual data recordings (R5, Part 5.2).

R6. Each Transmission Owner and Generator Owner shall time synchronize all SER, FR, and DDR data to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

6.2. Synchronized device clock accuracy within ± 1~~00~~ milli~~cro~~seconds of UTC.

M6. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R7. Each Transmission Owner and Generator Owner shall provide, upon request, all SER, FR, and DDR data to its Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Data shall be retrievable for the period of ~~3~~20 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within 30 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII[4] Comma Separated Value (CSV) format following Attachment 1.

7.4. FR and DDR data shall be provided either in CSV format or in electronic files that are formatted in conformance with C37.111, ~~(~~IEEE Standard Common Format for Transient Data Exchange (COMTRADE)~~)~~, revision C37.111-1999 or later.

[4] American Standard Code for Information Exchange

7.5. Data files shall be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M7. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R7. Evidence may include, but is not limited to: (1) actual data recordings; (2) dated transmittals to the requesting entity with formatted records; or (3) documents describing data storage capability, device specification, configuration, or settings.

R8. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR, or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M8. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R8. Evidence may include, but is not limited to: (1) dated reports of the discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated Corrective Action Plan transmittals to the Regional Entity and evidence of Corrective Action Plan implementation.

R9. Each Transmission Owner and Generator Owner of an applicable facility as specified in section A.4.2 that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance shall develop, maintain, and implement a Corrective Action Plan to provide the required capability. For each Corrective Action Plan, the Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Identify corrective actions and a timetable for completion.

9.2. Specify the circumstances causing the delay for fully or partially implementing Requirements R1 through R7 and explain how those circumstances are beyond the control of the responsible entity.

9.3. Identify revisions to the selected actions in Part 9.1, if any.

9.4. Identify updates to the timetable for implementing the selected actions in Part 9.1, if any.

9.5. Submit the Corrective Action Plan, and any revisions, to the Regional Entity, with a request to extend the time provided for compliance.

M9. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R9. Evidence may include, but is not limited to, documentation noting the date the Corrective Action Plan was developed or revised, documentation noting the date the Corrective Action Plan was submitted to the

Regional Entity with request to extend the time provided for compliance, and evidence of Corrective Action Plan implementation.

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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner and Generator Owner shall retain evidence, as per Requirements R1 through R8, for three calendar years.

If a Transmission Owner or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Violation Investigation~~
- ~~Self-Reporting~~

- ~~Complaints~~

~~1.4. Additional Compliance Information~~

~~None.~~

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the Elements (circuit breaker(s) or ~~IBR unit~~IBR Units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the Elements (circuit breaker(s) or ~~IBR unit~~IBR Units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent but less than or equal to 70 percent of the Elements (circuit breaker(s) or ~~IBR unit~~IBR Units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the Elements (circuit breaker(s) or ~~IBR unit~~IBR Units) identified in Section 4.2 Facilities.
R2	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, ~~and~~ 2.2, and 2.3 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, ~~and~~ 2.2, and 2.3 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, ~~and~~ 2.2, and 2.3 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, ~~and~~ 2.2, and 2.3 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical

			quantities for each Element.	electrical quantities for each Element.	quantities for each Element.	quantities for each Element.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

R5	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.
R6	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.
R7	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as

			directed by Requirement R7, Part 7.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	directed by Requirement R7, Part 7.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	directed by Requirement R7, Part 7.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	directed by Requirement R7, Part 7.2 failed to provide the requested data more than 60 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided less than or equal to 70 percent of the data in the proper data format.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and ~~failed to~~ provided a Corrective Action Plan to the Regional Entity more than 120

			calendar days after discovery of the failure.	days after discovery of the failure.	calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan and submitted it to the Regional Entity, but failed to submit any revisions to the Regional Entity as required by Requirement R9.	The Transmission Owner or Generator Owner developed and implemented a Corrective Action Plan and submitted it to the Regional Entity as required by Requirement R9, but failed to maintain it.	The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan, but failed to submit it to the Regional Entity as required by Requirement R9.	The Transmission Owner or Generator Owner failed to develop, maintain, or implement a Corrective Action Plan as required by Requirement R9.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-028-1: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011: IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

IEEE Std 2800-2022: IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.

Multiple Solar PV Disturbances in CAISO, Joint NERC and WECC Staff Report, April 2022.

NERC Reliability Standard PRC-002-5.

Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021, Joint NERC and Texas RE Event Report, September 2021.

Odessa Disturbance, Texas Event: June 4, 2022, Joint NERC and Texas RE Event Report, December 2022.

Version History

Version	Date	Action	Change Tracking
0	TBD	Adopted by NERC Board of Trustees	New

Attachment 1

Sequence of Events Recording (SER) Data Format

(Requirement R7, Part 7.3)

Date, Time, Local Time Code, Plant Name, Device[5], State[6]

08/27/23, 23:58:57.110, -5, Plant name 1, Breaker 1, Close

08/27/23, 23:58:57.082, -5, Plant name 2, Breaker 2, Close

08/27/23, 23:58:47.217, -5, Plant name 1, ~~IBR unit~~IBR Unit 1, Open

08/27/23, 23:58:47.214, -5, Plant name 2, ~~IBR unit~~IBR Unit 2, Open

08/27/23, 23:58:47.217, -5, Plant name 1, ~~IBR unit~~IBR Unit 1, undervoltage ride-through mode

08/27/23, 23:58:47.214, -5, Plant name 2, ~~IBR unit~~IBR Unit 2, dc overcurrent trip

[5] Device name may include specific names of breakers or ~~IBR unit~~IBR Units as appropriate.

[6] Breaker status and any other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is acceptable. For ~~IBR unit~~IBR Unit level data, fault codes, alarms, change in operating mode etc. are also acceptable.

Implementation Plan

Project 2021-04
Reliability Standards PRC-002-5 and PRC-028-1

Applicable Standard(s)

- PRC-002-5 Disturbance Monitoring and Reporting Requirements
- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

Requested Retirement(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner (TO)
- Generator Owner (GO)

General Considerations

Additional time to implement Reliability Standard PRC-002-5 is not provided because the revisions are clarifying in nature to exclude Inverter-Based Resources from PRC-002 applicability as they are included in PRC-028. The revision to PRC-002 does not require any procurement or installation of disturbance monitoring equipment.

The Reliability Standard PRC-028-1 is expected to have wide ranging impact on TOs and GOs as many existing and new facilities would be required to have disturbance monitoring equipment. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities. The Implementation Plan takes into account scheduling outages needed to implement sequence of events recording, fault recording, and dynamic disturbance recording capability. An entity owning only one (1) identified generating plant/Facility is allowed three (3) calendar years for implementation to accommodate normal outage schedules. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities. The Implementation Plan recognizes Federal Energy Regulatory Commission’s directive to have this standard effective and enforceable before 2030.[1]

[1] See Order No. 901 at P226.

Effective Date of PRC-002-5

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-002-5 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-002-5 shall become effective 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.

Effective Date of PRC-028-1 and Phased-in Compliance Dates

The effective date for proposed Reliability Standard PRC-028-1 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard PRC-028-1

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance Date for PRC-028-1 Requirements R1-R7

For Plants/Facilities in commercial operation on or before the effective date:

Entities shall comply with Requirements R1 through R7 at 50% of their generating plants/Facilities within three (3) calendar years of the effective date of PRC-028-1 and 100% of their generating plant/Facilities by January 1, 2030.

Entities that are required to monitor only one (1) generating plant/Facility shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of Reliability Standard PRC-028-1.

For Plants/Facilities entering commercial operation within one year after the effective date:
Entities shall comply with Requirements R1 through R7 by the end of the first calendar year that is 12 months following the effective date of the standard.

For Plants/Facilities entering commercial operation one year or later after the effective date:
Entities shall comply with Requirements R1 through R7 at the date of entering commercial operation.

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than nine (9) months after the effective date of Reliability Standard PRC-028-1.

Compliance Date for PRC-028-1 Requirement R9

Entities shall comply with Requirement R9, as applicable, by no later than January 1, 2029.

Retirement Date

Reliability Standard PRC-002-4 shall be retired immediately prior to the effective date of Reliability Standard PRC-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan ~~(Draft)~~

Project 2021-04
Reliability Standards PRC-002-5 and PRC-028-1

Applicable Standard(s)

- PRC-002-5 Disturbance Monitoring and Reporting Requirements
- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

Requested Retirement(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner (TO)
- Generator Owner (GO)

General Considerations

Additional time to implement Reliability Standard PRC-002-5 is not provided because the revisions are clarifying in nature to exclude ~~inverter~~Inverter-~~based~~ Based ~~resources~~ Resources from PRC-002 applicability as they are included in PRC-028. The revision to PRC-002 does not require any procurement or installation of disturbance monitoring equipment.

The Reliability Standard PRC-028-1 is expected to have wide ranging impact on TOs and GOs as many existing and new facilities would be required to have disturbance monitoring equipment. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities. The Implementation Plan takes into account scheduling outages needed to implement sequence of events recording, fault recording, and dynamic disturbance recording capability. An entity owning only one (1) identified generating plant/Facility is allowed three (3) calendar years for implementation to accommodate normal outage schedules. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities. The Implementation Plan recognizes Federal Energy Regulatory Commission's directive to have this standard effective and enforceable before 2030.[1]

[1] See Order No. 901 at P226.

Effective Date of PRC-002-5

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-002-5 shall become effective on ~~the later of: (1)~~ the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority~~; or (2) the effective date of PRC-002-4~~.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-002-5 shall become effective ~~on the later of: (1)~~ the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction~~; or (2) the effective date of PRC-002-4~~.

Effective Date of PRC-028-1 and Phased-in Compliance Dates

The effective date for proposed Reliability Standard PRC-028-1 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard PRC-028-1

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance Date for PRC-028-1 Requirements R1-R7

For Plants/Facilities in commercial operation on or before the effective date:

Entities shall ~~be fully compliant~~ comply with Requirements R1 through R7 at 50% ~~percent~~ of their generating plants/Facilities within three (3) calendar years of the effective date of PRC-028-1 and ~~fully compliant at~~ 100% of their generating plant/Facilities by January 1, 2030~~within sixfive (56) calendar years of the effective date of Reliability Standard PRC-028-1~~.

Entities that are required to monitor only one (1) generating plant/Facility shall ~~be fully compliant~~ comply with Requirements R1 through R7 within three (3) calendar years of the effective date of Reliability Standard PRC-028-1.

~~Entities with more than one (1) generating plant/Facility are encouraged to develop a strategy, to be shared with ERO Compliance Monitoring and Enforcement Program staff as requested, for how they will implement Reliability Standard PRC-028-1 across their generating fleet.~~

For Plants/Facilities entering commercial operation within one year after the effective date:
Entities shall comply with Requirements R1 through R7 by the end of the first calendar year that is 12 months following the effective date of the standard.

For Plants/Facilities entering commercial operation one year or later after the effective date:
Entities shall comply with Requirements R1 through R7 at the date of entering commercial operation.

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than ~~be 100% compliant on the first day of the first calendar quarter~~ nine (9) months after the effective date of Reliability Standard PRC-028-1.

Compliance Date for PRC-028-1 Requirement R9

Entities shall comply with Requirement R9, as applicable, by no later than January 1, 2029.

Retirement Date

~~The~~ Reliability Standard PRC-002-4 shall be retired immediately prior to the effective date of Reliability Standard PRC-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

~~Prior Implementation Plan~~

~~The following element of the Implementation Plan for PRC-002-4 is incorporated herein and modified in case PRC-002-4 is superseded by PRC-002-5 prior to becoming effective:~~

~~Reliability Coordinators in the Eastern Interconnection shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-4 or six (6) months of the effective date of PRC-002-5, whichever occurs first.~~

Unofficial Comment Form

Project 2021-04 Modifications to PRC-002 – Phase II

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-04 Modifications to PRC-002 – Phase II** by **8 p.m. Eastern, Thursday, April 11, 2024.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 470-542-6882.

Background Information

This project will be completed in two phases. The first phase addressed the scope regarding notifications relative to the sequence of events recording (SER) and fault recording (FR) data, and to clearly identify the BES Element owners that need to have SER and FR data for transformers and transmission lines with the associated identified bus in the Glencoe Light and Power SAR.

The second phase will address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.

Questions

1. Do you agree with the modification in “Applicability, Section 4.2. Facilities” in PRC-002-5 and PRC-028-1?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with introduction of Requirement R9 in PRC-028-1 requiring Entities of an applicable facility that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance to develop, maintain, and implement a Corrective Action Plan?

   ☐ Yes
   ☐ No

   Comments:

5. Provide any additional comments for the standard drafting team to consider, if desired.

   Comments:

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Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-002-5)

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 PRC-002-5. 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.

VRF Justification for PRC-002-5, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R1

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R2

The VRF did not change from the previously FERC approved PRC-002-4Reliability Standard.

VSL Justification for PRC-002-5, Requirement R2

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R3

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R3

VSLs for PRC-002-5, Requirement R3			
Lower	Moderate	High	Severe
The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of

number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-002-5, Requirement R3	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justification for PRC-002-5, Requirement R4

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R4

VSLs for PRC-002-5, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.

VSL Justifications for PRC-002-5, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R4	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R5
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R6

VSLs for PRC-002-5, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R6	
Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R7

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R7

VSLs for PRC-002-5, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities,

total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-002-5, Requirement R7	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R8
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R8
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R9
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R9
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R10
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R10
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R11
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R11

VSLs for PRC-002-5, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-002-5, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-028-1)

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 PRC-028-1. 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-028-1

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.

VSL Justifications for PRC-028-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R1	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
	capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as

directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R4	
for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

VSL Justifications for PRC-028-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R6	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 failed to provide the requested data more than 60 calendar days

more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R7	
Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and failed to provide a Corrective Action Plan to the Regional Entity more than 120 calendar

than or equal to 100 calendar days after discovery of the failure.	than or equal to 110 calendar days after discovery of the failure.	than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R8	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R9	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R9	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan and submitted it to the Regional Entity, but failed to submit any revisions to the Regional Entity as required by Requirement R9.	The Transmission Owner or Generator Owner developed and implemented a Corrective Action Plan and submitted it to the Regional Entity as required by Requirement R9, but failed to maintain it.	The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan, but failed to submit it to the Regional Entity as required by Requirement R9.	The Transmission Owner or Generator Owner failed to develop, maintain, or implement a Corrective Action Plan as required by Requirement R9.

VSL Justifications for PRC-028-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-028-1)

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 PRC-028-1. 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-028-1

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the Elements (circuit breaker(s) or IBR units) identified in Section 4.2 Facilities.

VSL Justifications for PRC-028-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R1	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
	capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as

directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R4	
for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

VSL Justifications for PRC-028-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R6	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 failed to provide the requested data more than 60 calendar days

more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.5 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R7	
Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and failed to provide a Corrective Action Plan to the Regional Entity more than 120 calendar

than or equal to 100 calendar days after discovery of the failure.	than or equal to 110 calendar days after discovery of the failure.	than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R8	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R9	
Proposed VRF	Lower
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R9	
Proposed VRF	Lower
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R9			
Lower	Moderate	High	Severe
The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan and submitted it to the Regional Entity, but failed to submit any revisions to the Regional Entity as required by Requirement R9.	The Transmission Owner or Generator Owner developed and implemented a Corrective Action Plan and submitted it to the Regional Entity as required by Requirement R9, but failed to maintain it.	The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan, but failed to submit it to the Regional Entity as required by Requirement R9.	The Transmission Owner or Generator Owner failed to develop, maintain, or implement a Corrective Action Plan as required by Requirement R9.

VSL Justifications for PRC-028-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Technical Rationale for Reliability Standard PRC-002-5

March 2024

PRC-002-5 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the Bulk Electric System (BES), the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for inverter-based resources (IBRs) to aid with event analysis, performance monitoring, and disturbance-based IBR generating facility model validation. The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the BES. Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. Introducing IBR monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for IBRs is created instead of revising the Reliability Standard PRC-002. To avoid any overlap between the Reliability Standards PRC-002 and PRC-028, BES Elements within inverter-based portions of generating plants/Facilities meeting the criteria set by Inclusion I2, part (b) or Inclusion I4 of the BES definition. Example in Figure 1 is provided to clarify applicability of Reliability Standards PRC-002 and PRC-028. The IBR generating facility in this example meets the criteria in inclusion I2 of the BES definition. The BES bus in substation Scott is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for BES Elements associated with the identified BES bus are per the Reliability Standard PRC-002 except for Elements associated with the IBR generating facility, i.e., circuit breaker 3. The SER, FR, and DDR data requirements for the IBR generating facility are specified in the Reliability Standard PRC-028.

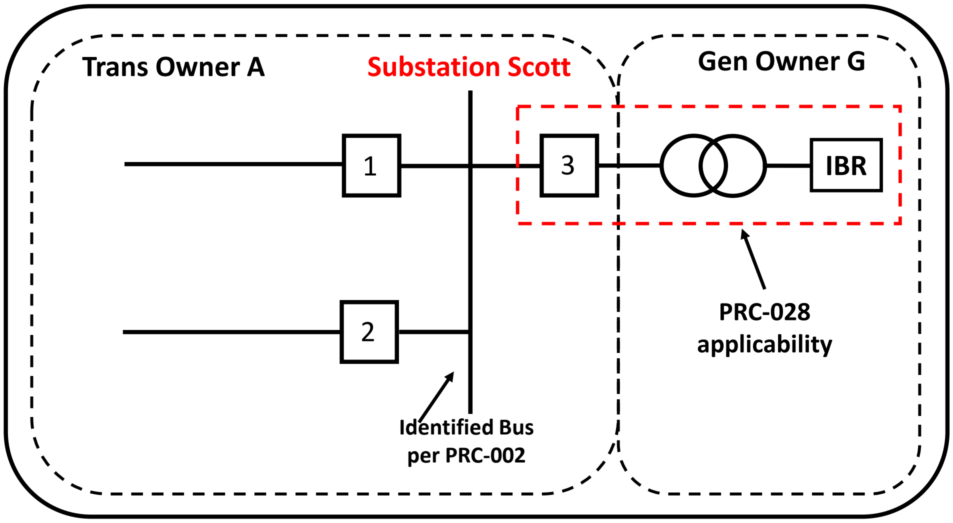


Figure 1: Example to Clarify Applicability of PRC-002 Versus PRC-028

Rationale for Requirement R1

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the Disturbance Monitoring Standard Drafting Team (DMSDT) data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-5, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three-phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

5. Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three-phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.

7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three-phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three-phase short circuit MVA of the newly identified BES bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B, and C are identified in Step 6. The maximum three-phase short circuit MVA of buses A, B, and C is 1600 MVA, 1500 MVA, and 1550 MVA respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three-phase short circuit MVA of buses A, B, and C is 1550 MVA, 1675 MVA, and 1600 MVA respectively. The bus B is the one with highest maximum three-phase short circuit MVA now. The three-phase short circuit MVA of bus B is within 15% of the three-phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three-phase short circuit MVA of buses A, B, and C is 1500 MVA, 1750 MVA, and 1650 MVA respectively. The three-phase short circuit MVA of bus B is greater than 15% of three-phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse

power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of "directly connected" BES Elements are notified. For the purposes of this standard, "directly connected" BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 2 and 3 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

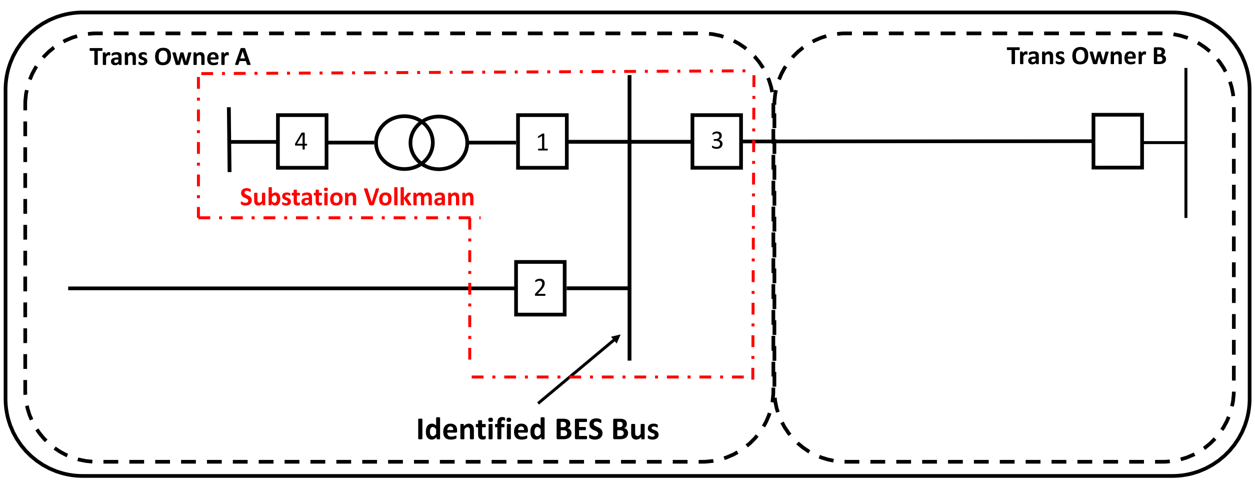


Figure 2: Straight Bus Configuration – Single Owner

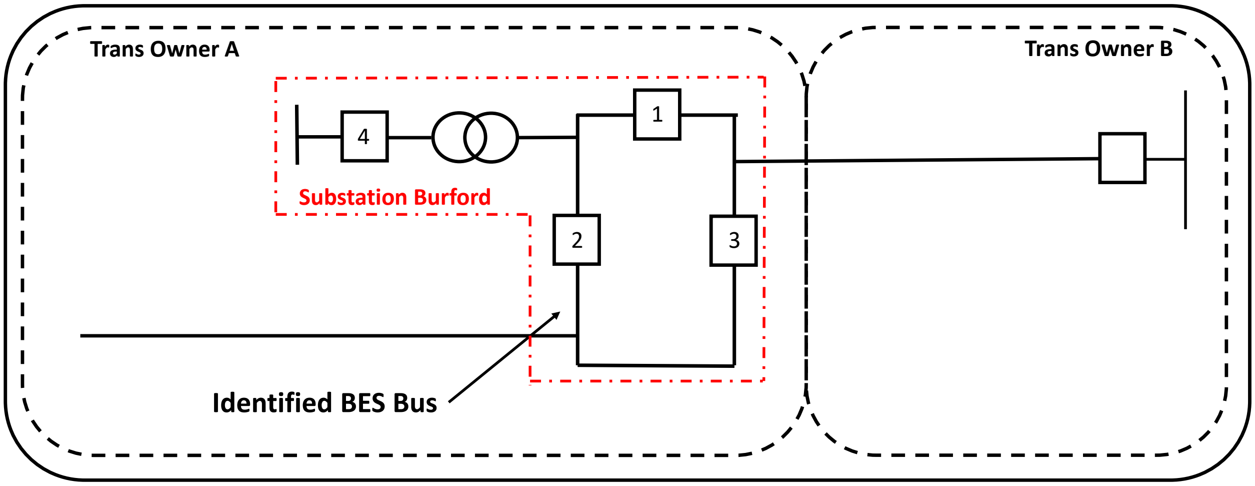


Figure 3: Ring Bus Configuration – Single Owner

Figures 4 and 5 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

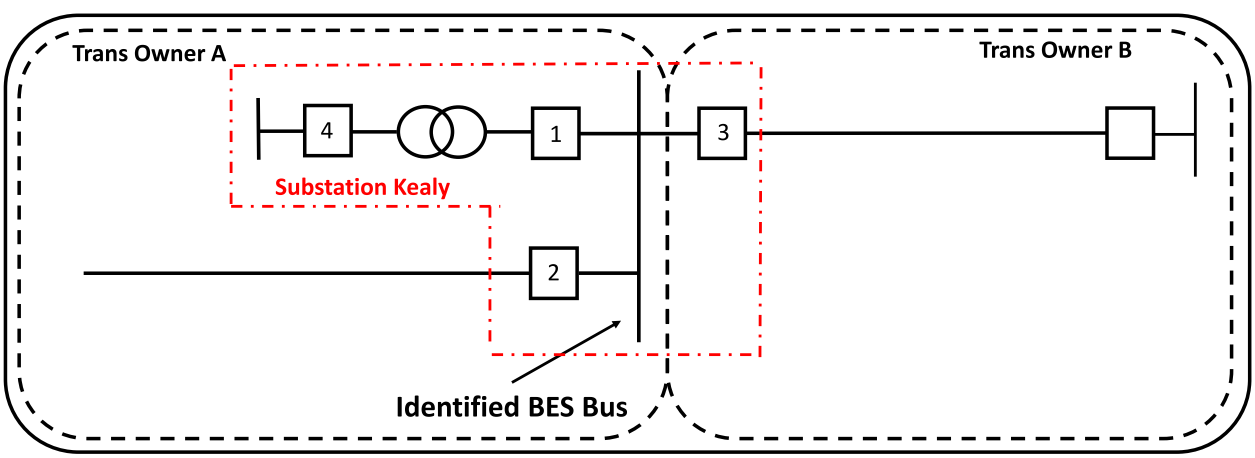


Figure 4: Straight Bus Configuration – Multiple Owners

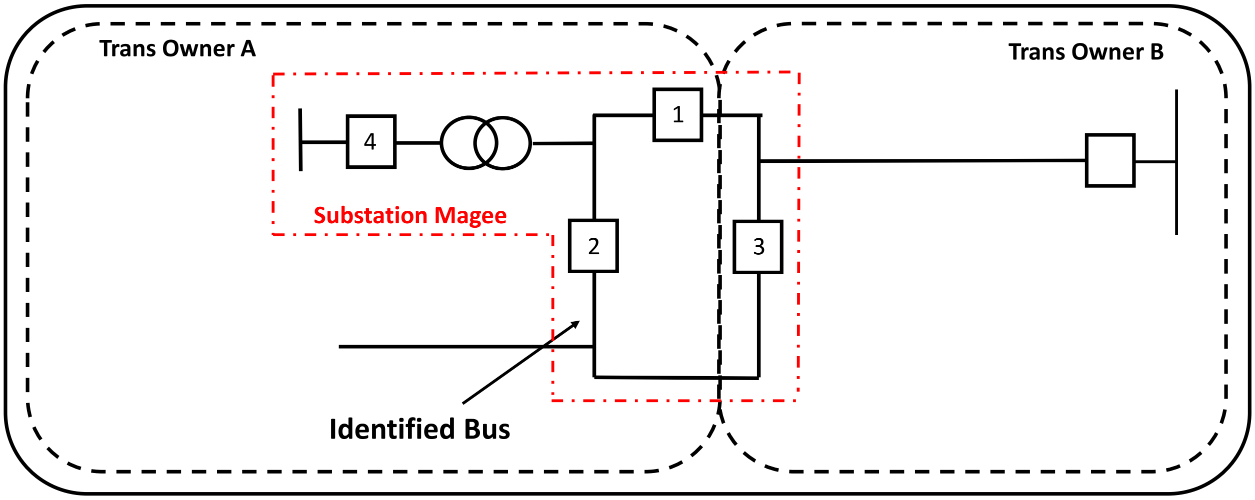


Figure 5: Ring Bus Configuration – Multiple Owners

For examples in Figures 4 and 5, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 6 shows an example with a generator interconnection. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

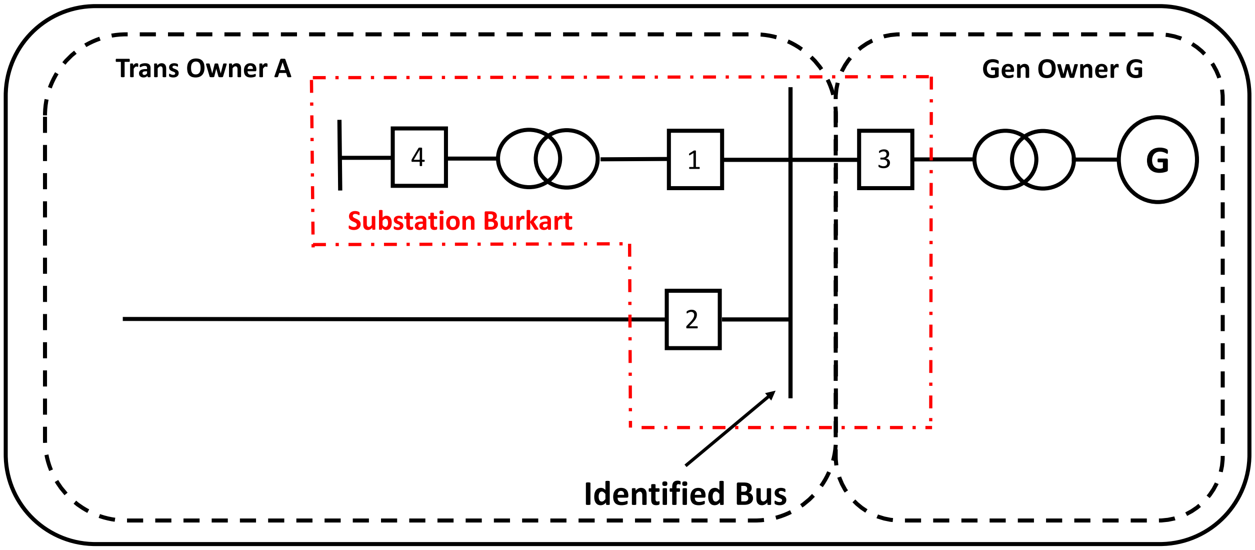


Figure 6: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 7, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

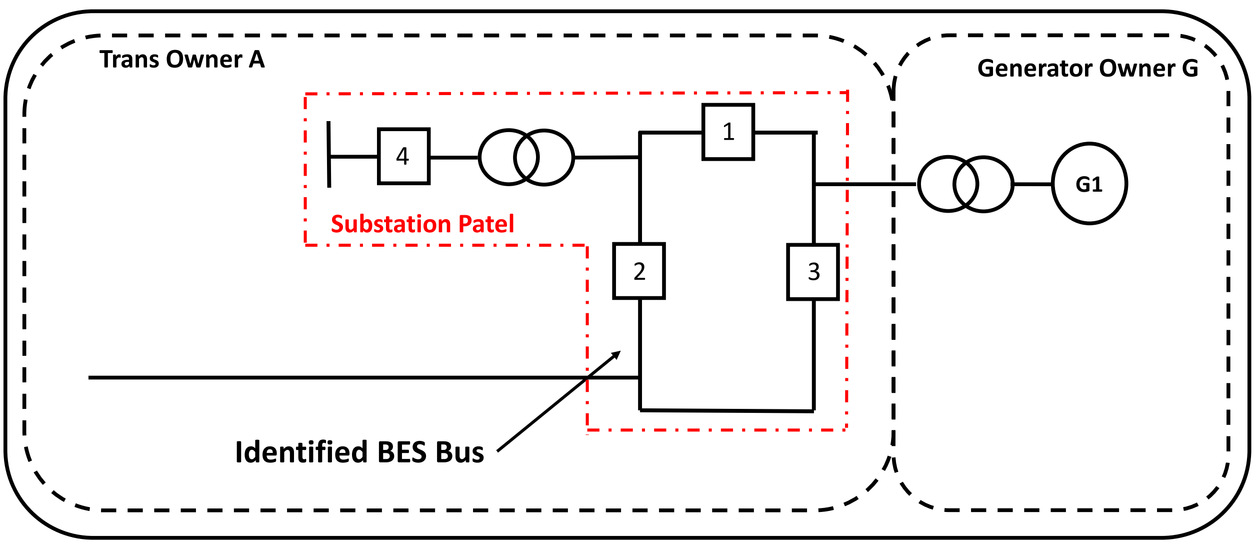


Figure 7: Generator Interconnection to Ring Bus

Figure 8 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical

bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

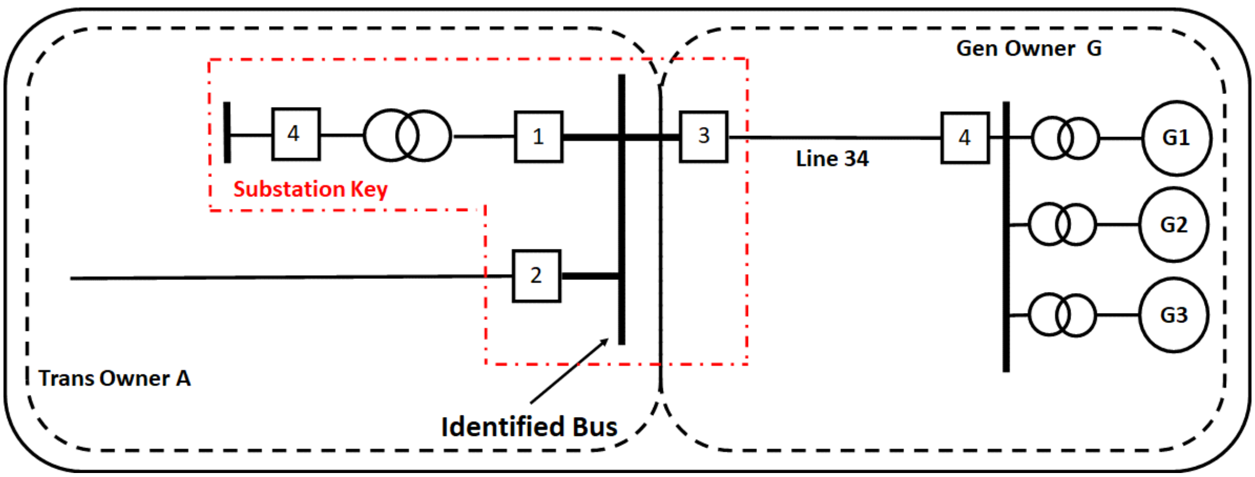


Figure 8: Generator Interconnection via Line 34

Figure 9 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3, and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

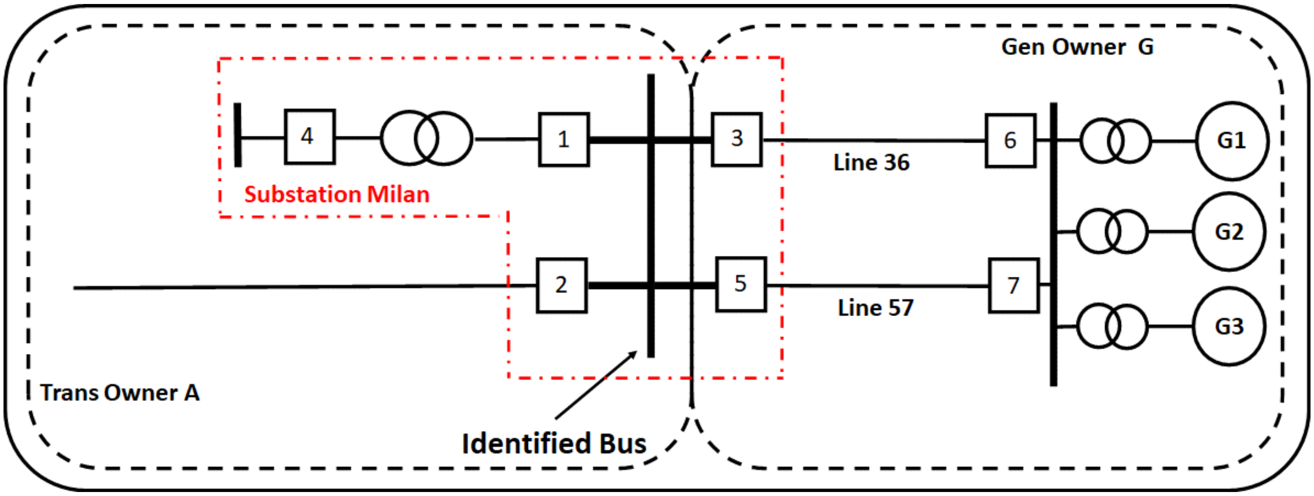


Figure 9: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification Transmission Owner B

Greetings,

In accordance with NERC Standard PRC-002-5, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Rationale for Requirement R2
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element directly connected to a BES bus. Change of state of circuit breaker position and time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position.

However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Examples in Figures 10, 11, and 12 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement R3
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads 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 are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements directly connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element directly connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities, it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

Examples in Figures 10, 11, and 12 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

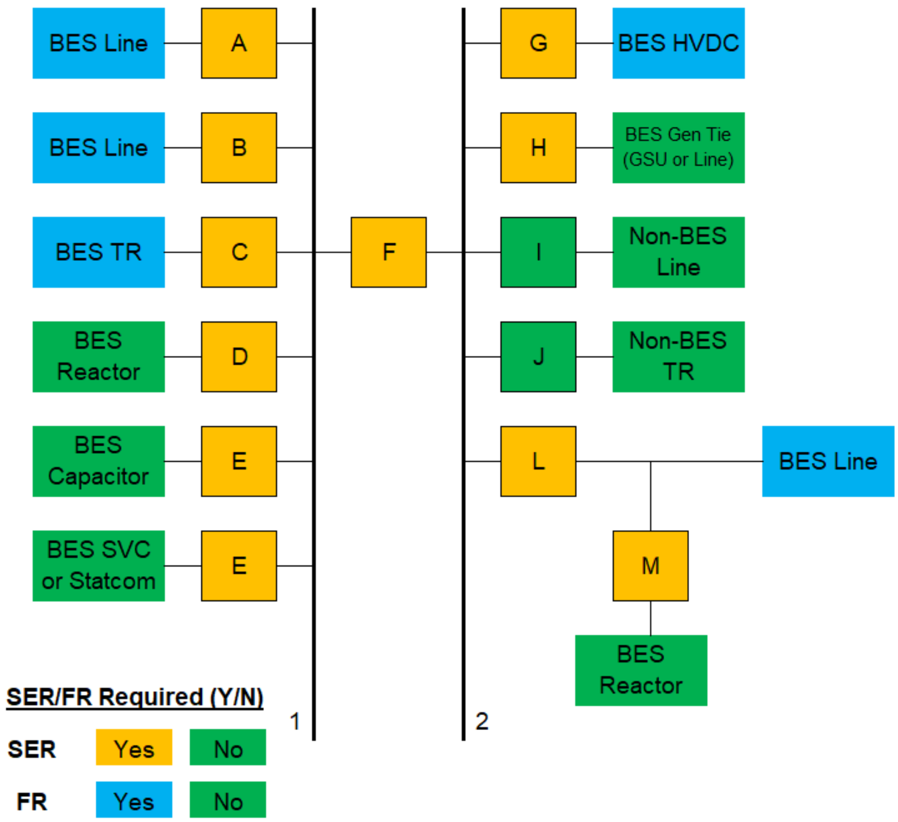


Figure 10: Straight BES Buses

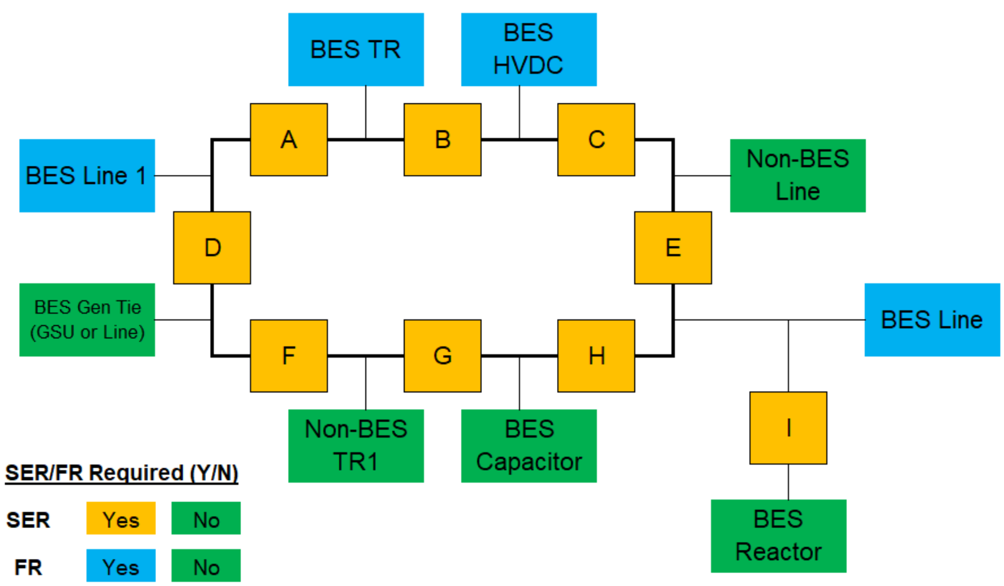


Figure 11: Ring BES Bus

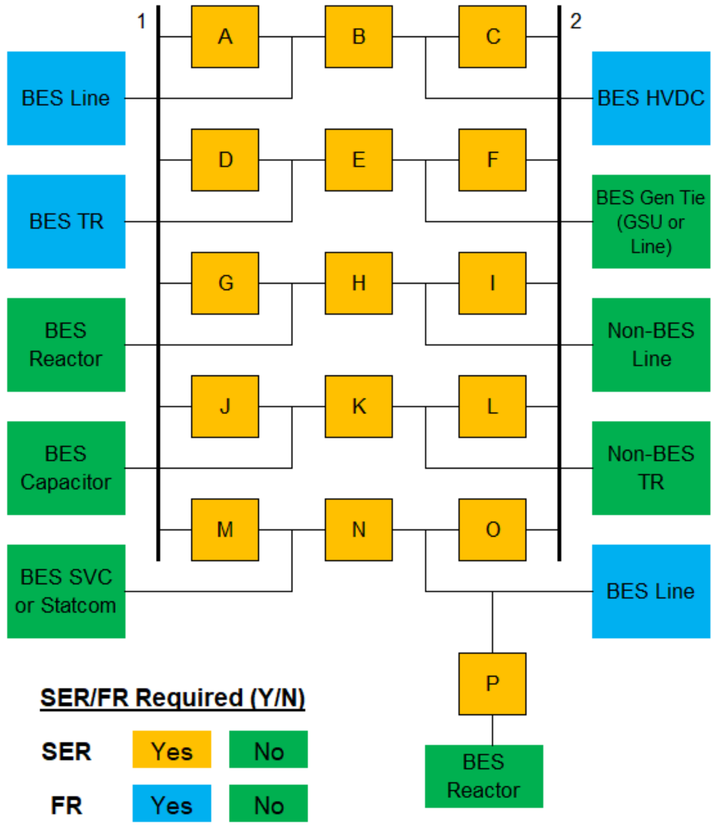


Figure 12: Breaker and Half BES Bus

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example, residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three

phase currents:

$$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

<u>Voltage Recordings</u>
Voltages are to be recorded or accurately determined at applicable BES buses

Rationale for Requirement R4
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30- contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Rationale for Requirement R5
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for

specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data, as per Requirement R5, is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element, as defined by the Reliability Coordinator, must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and

oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System-wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means, and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes.

However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather, the drafting team believes this determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR, such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Rationale for Requirement R6

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral

voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three-phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Rationale for Requirement R7
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at eitherthe high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the ‘what’ of DDR, not the ‘how’. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again, it must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement R8

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post- contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Rationale for Requirement R9

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.
DDR data contains the dynamic response of a power System to a Disturbance and is used for

analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Rationale for Requirement R10

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment.

Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement R11

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30 calendar days (or the granted extension time), subject to Part 11.2, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10 calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity, or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.2 specifies the maximum time frame of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.1 specifies that the minimum time period of 10 calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Rationale for Requirement R12

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90 calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System.

Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90 calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Technical Rationale for Reliability Standard PRC-028-1

March 2024

PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter Based Resources

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, and Odessa disturbances) have identified a need for disturbance monitoring for Inverter-Based Resources[1] (IBRs) to aid with event analysis, performance monitoring, and disturbance-based IBR generating facility model validation. These disturbance reports recommended to install disturbance monitoring equipment (DME) at wind and solar photovoltaic (PV) resources to ensure adequate data is available for event analysis, performance monitoring, and validating IBR generating facility models. The recommendation included plant-level high resolution oscillography data, plant SCADA data with a resolution of one second, sequence of events recording for all IBR Units[2] that include all fault codes, and at least one IBR Unit on each collector feeder configured to capture high resolution oscillography data within the IBR Unit.

The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. The recent disturbance analyses of events involving IBRs (e.g., Blue Cut Fire, Canyon 2 Fire, and Odessa disturbances) have demonstrated that IBR's response to a normally cleared few cycle fault is undesirable and poses risk to system reliability. All these disturbance analyses have identified that IBRs involved did not have sufficient monitoring data to understand the plants' responses. The initiating event, e.g., a normally cleared transmission fault, was not a large-scale system disturbance. However, IBR plant's undesirable response due to a system fault, resulted in a larger system disturbance. Adequate monitoring data is required to understand IBR plant's performance. Most of the IBRs involved in these disturbances did not have, and were not required to have, adequate disturbance monitoring data. The lack of disturbance monitoring data available from these facilities led to difficulty in adequately assessing the events. Introducing IBR monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by

[1] Inverter-Based Resource as of 02/22/2024: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell. **(This footnote will be removed when IBR definition is finalized)**

[2] IBR Unit as of 02/23/2024: An individual device that uses a power electronic interface, such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connects at a single point on the collector system; or a grouping of multiple devices that uses a power electronic interface(s), such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connect together at a single point on the collector system. **(This footnote will be removed when IBR Unit definition is finalized)**

the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for IBRs is created instead of revising the Reliability Standard PRC-002.

The Transmission Owners and Generator Owners, as applicable, will have the responsibility for ensuring that adequate data is available for applicable Elements at the applicable IBR generating facilities. This standard requires that sequence of events recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data is available from the applicable IBR generating facilities.

Rationale for Applicability Section
Functional Entities
The two functional entities that are responsible for implementing disturbance monitoring equipment and collecting recording data are: Generator Owner and Transmission Owner. The standard is only applicable to the Transmission Owner in cases where Transmission Owner owns equipment (e.g., circuit breaker(s), main step-up transformer, collector bus, dynamic reactive device, etc.) within the IBR Plant.

Applicable Facilities
The BES Inverter-Based Resources and Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV, are in the scope of this standard.

Order No. 901 directed NERC to develop Reliability Standards "to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment." Order No. 901 at P 85. FERC continued, "We further agree with the findings in NERC reports (e.g., a lack of high-speed data captured at the IBR or plant-level controller and low-resolution time stamping of inverter sequence of event recorder information has hindered event analysis) and direct NERC through its standard development process to address these findings."

In distinguishing among the different types of IBRs and their registration status that must be covered by the standards, FERC stated: "Where necessary to describe our directives, however, we differentiate between IBRs registered with NERC (or which will be registered pursuant to the Commission's directives in *Registration of Inverter-based Resources*, 181 FERC ¶ 61,124 (2022) (IBR Registration Order)) and therefore subject to the Reliability Standards (i.e., registered IBR), IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards (i.e., unregistered IBRs), and IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk-Power System (i.e., IBR-DER)." Order No. 901 at n. 14.

In proposed PRC-028-1, the standard drafting team includes both categories of generation that would be registered under proposed changes to NERC Rules of Procedure consistent with Order No. 901. In February

2024, the NERC Board of Trustees approved revisions to the Rules of Procedure to expand the Generator Owners and Generator Operators registered with NERC for compliance purposes. In addition to owners and operators of generating Facilities, NERC will register owners and operators of sub-BES IBRs meeting the following criteria: non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. More information on these changes, which are pending FERC approval, are available at: https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board%20Open%20Agenda%20Package%20-%20February%2022%202024_ATTENDEE.pdf [nerc.com]

The standard drafting team understands that NERC will initiate a separate *Glossary* revision effort to revise the definition of Generator Owner and Generator Operator consistent with the proposed Rules of Procedure definitions for registration. This effort will complete well in advance of the team's proposed [X] year implementation plan for Reliability Standard PRC-028-1.

The following Elements associated with Inverter-Based Resources noted above are in the scope of this standard:

- Circuit breaker(s)
- Main power transformer(s)
- Collector bus
- Shunt static or dynamic reactive device(s)
- At least one IBR Unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus

The following examples are provided to clarify applicability of the PRC-028 standard.

Example 1: Applicability of PRC-028

Figure 1 shows a typical single line diagram of an IBR generating facility. The IBR generating facility is connected to the transmission system via a short tie-line. The length of collector feeder #1, #2, and #3 is 3000 ft, 2500 ft, and 2800 ft, respectively. IBR Units #6 and #7 are connected to collector feeder #1 at 2800 ft and 3000 ft distance from the collector bus, respectively. IBR Unit #18 is connected to collector feeder #3 at 2800 ft distance from the collector bus. In other words, these IBR Units #6, #7, and #18 are connected at a distance ≥ 90% of the longest collector feeder from the collector bus. This IBR generating facility is equipped with a dynamic reactive device (e.g., synchronous condenser, static VAR compensator, etc.) connected to the collector bus.

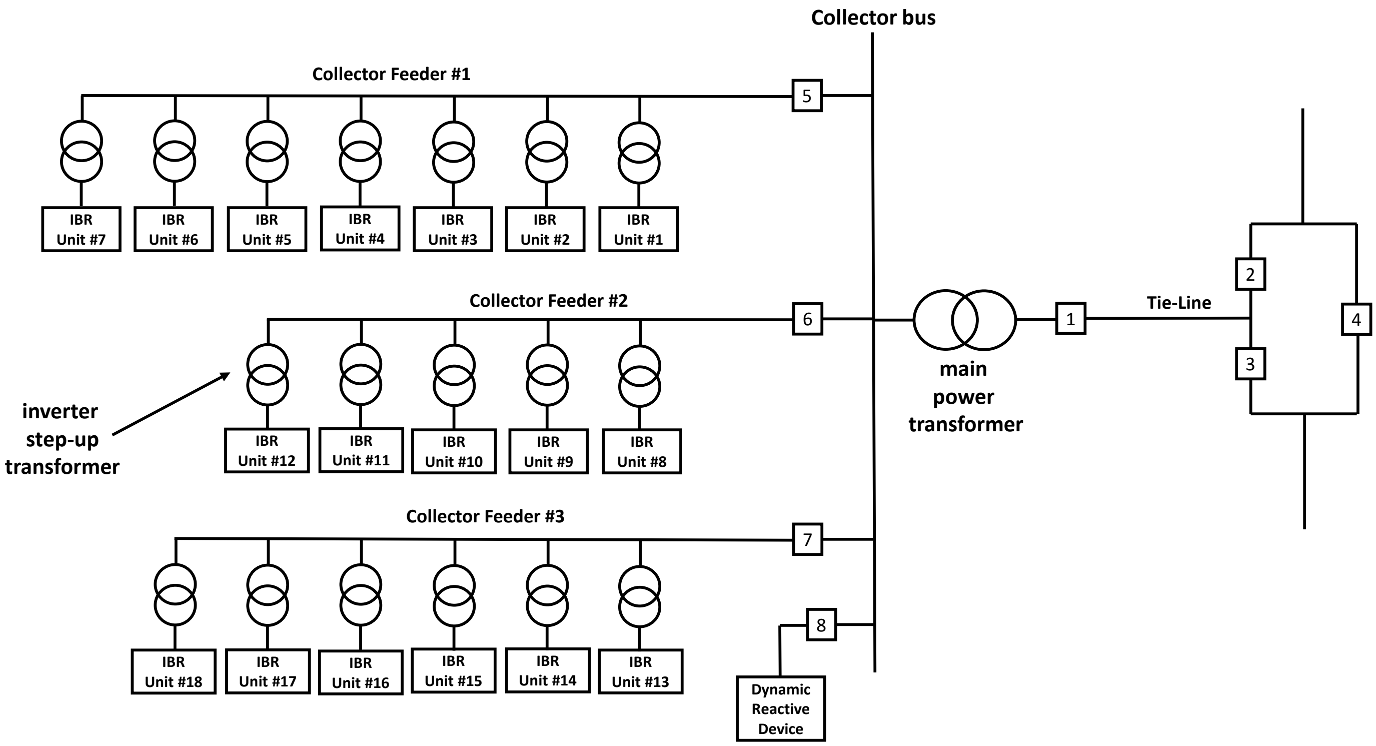


Figure 1: Typical IBR Generating Facility Single Line Diagram

SER Data: The SER data is required for circuits breaker 1, 5, 6, 7, and 8. Circuit breaker 1 is associated with the main power transformer. Circuit breakers 5, 6, 7, and 8 are associated with the collector bus. The SER data for IBR Unit #6, #7, or #18 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus.

FR Data: The FR data is required from high side terminals of the main power transformer. In this example, the IBR plant consists of only one main power transformer. If the IBR plant consists of more than one main power transformer, then FR data for each main power transformer is required. The FR data for IBR Unit #6, #7, or #18 is required, as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus. As the IBR plant is equipped with the dynamic reactive device, the FR data for it is also required.

DDR Data: The DDR data is required from high side terminals of the main power transformer. If the IBR plant consists of more than one main power transformer, then DDR data for each main power transformer is required. The DDR data from individual IBR Units is not required.

<u>Example 2: Applicability of PRC-028 (Facility with two collector buses and main power transformers)</u>

Figure 2 shows a single line diagram of an IBR generating facility with two collector buses and main power transformers. The IBR generating facility is connected to the transmission system via a short tie-line. The collector feeders #1 and #2 are connected to collector bus #1. The collector feeders #3 and #4 are connected to collector bus #2. The length of collector feeder #1, #2, #3, and #4 is 3000 ft, 2500 ft, 2800 ft, and 2600 ft, respectively. The collector feeder #1 is the longer of two collector feeders connected to collector bus #1. IBR Units #6 and #7 are connected to collector feeder #1 at 2800 ft and 3000 ft distance from the collector bus #1 respectively. IBR Unit #12 is connected to collector feeder #2 at 2500 ft from the collector bus #1. The IBR Units #6 and #7 are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #1. The collector feeder #3 is the longer of two collector feeders connected to collector bus #2. IBR Units #17 and #18 are connected to collector feeder #3 at 2600 ft and 2800 ft distance from the collector bus #2 respectively. IBR Unit #23 is connected to collector feeder #4 at 2600 ft from the collector bus #2. The IBR Units #17, #18, and #23 are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #2.

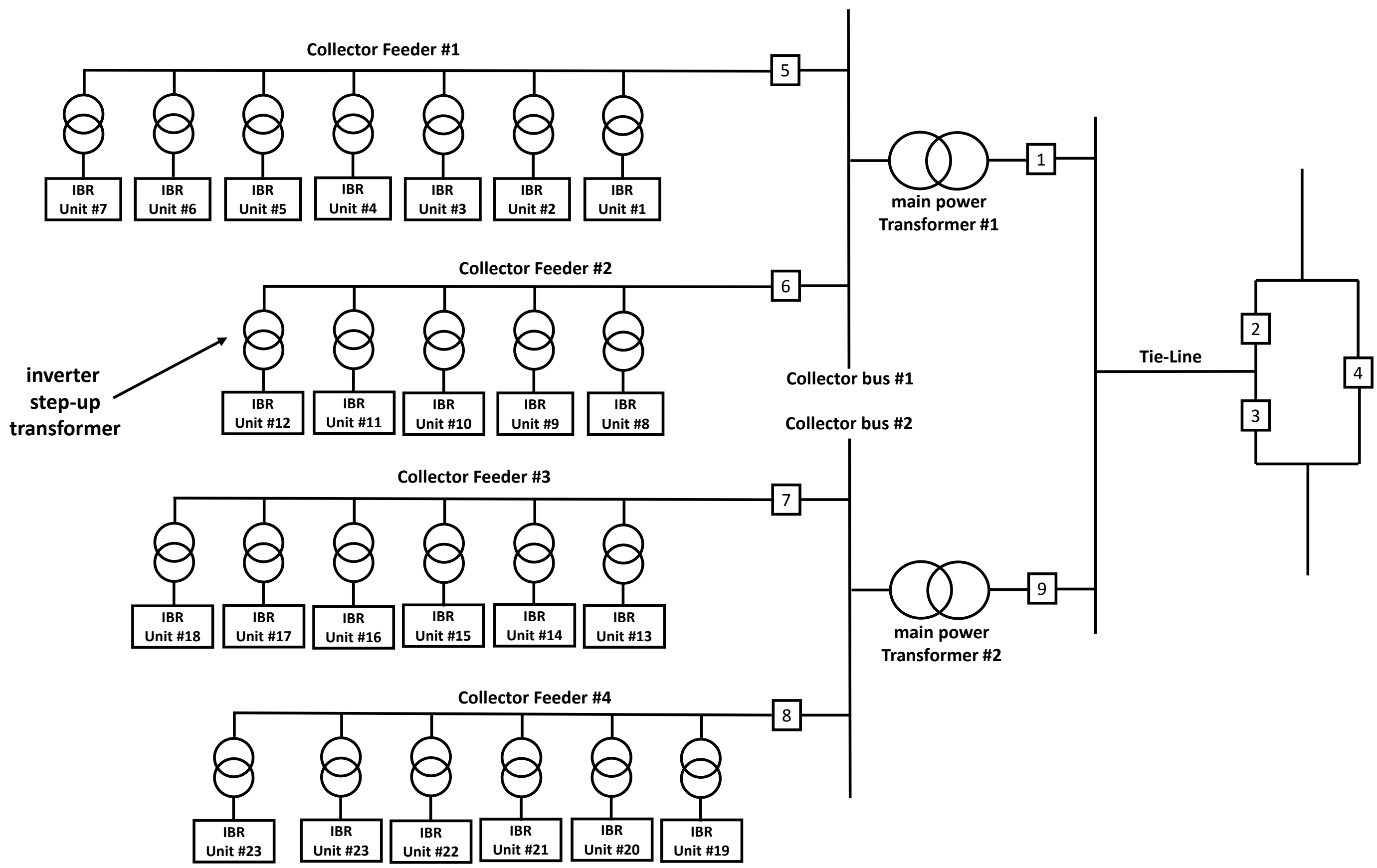


Figure 2: Typical IBR Generating Facility with two collector buses and main power transformers

SER Data: The SER data is required for circuit breakers 1, 5, 6, 7, 8, and 9. Circuit breakers 1 and 9 are associated with main power transformers. Circuit breakers 5, 6, 7, and 8 are associated with collector buses #1 and #2. The SER data for IBR Unit #6 or #7 is required, as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #1. The SER data for IBR Unit #17, #18, or #23 is required, as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #2.

FR Data: The FR data is required from high side terminals of both main power transformers. The SER data for IBR Unit #6 or #7 is required, as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #1. The SER data for IBR Unit #17, #18, or #23 is required, as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #2.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 3: Applicability of PRC-002 versus PRC-028

Figure 3 shows an example of IBR interconnection to the transmission system via Line 34. The BES bus in substation Wu is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for the identified BES bus are per the requirements in the Reliability Standard PRC-002. The IBR generating facility in this example meets the criteria set by inclusion I2 of the BES definition. Hence, the Reliability Standard PRC-028 is applicable to the IBR generating facility.

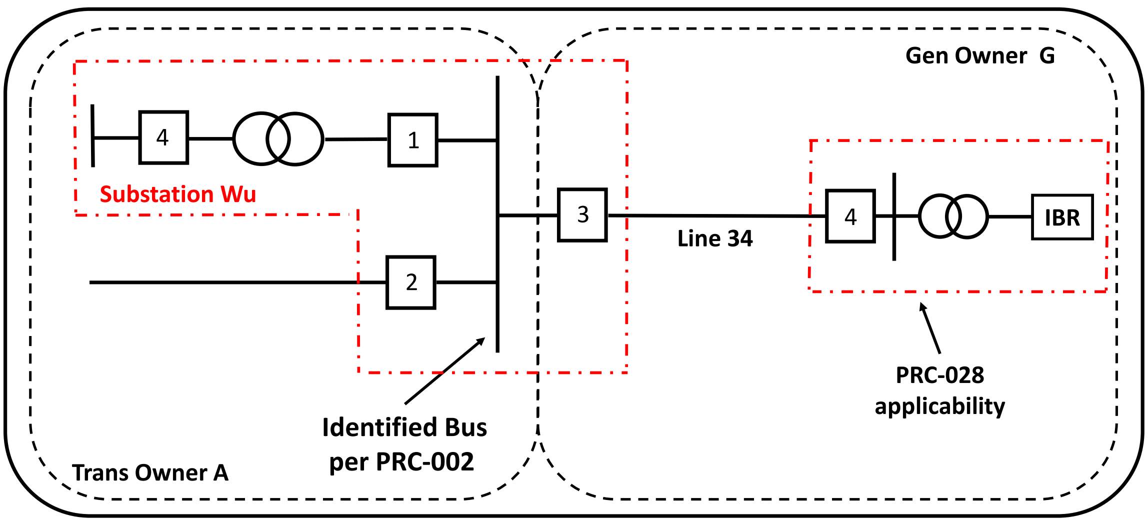


Figure 3: IBR Interconnection – Applicability of PRC-002 versus PRC-028

Example 4: Transmission Owner owned Equipment within the IBR generating facility

Figure 4 shows an example of an IBR interconnection where Transmission Owner A owns circuit breaker 3 associated with an IBR generating facility. In this case, Transmission Owner A is responsible for SER data for circuit breaker 3. It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an IBR generating facility. However, in cases where this is true, Transmission Owner is responsible for SER, FR, and DDR data, as applicable, required by the Reliability Standard PRC-028.

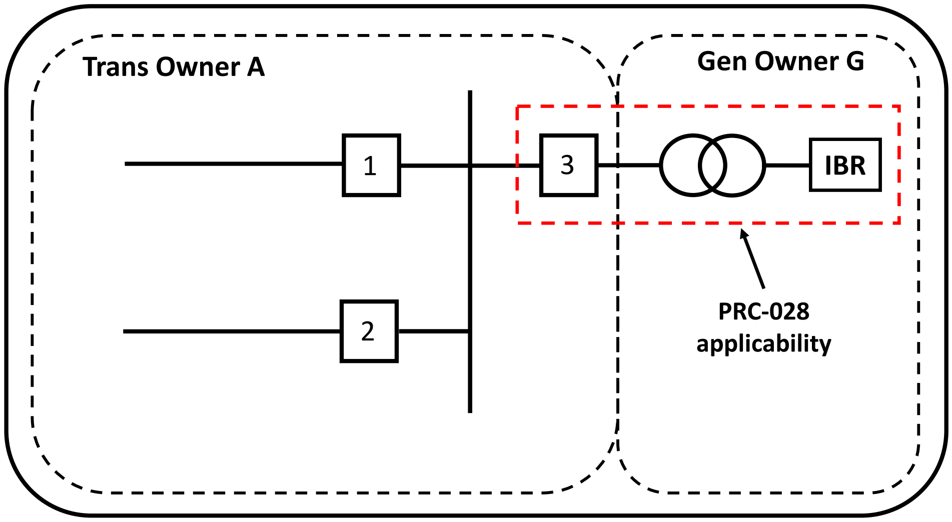


Figure 4: Transmission Owner owned Equipment within an IBR Plant

Rationale for Requirement R1

The standard requires you to capture SER data from circuit breakers and IBR Units within the IBR generating facility. At least one IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus must have the data specified in R1, Part 1.2 and Part 1.3.

Change of state of circuit breaker position and IBR Unit data, time stamped according to Requirement R7 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of IBR generating facility's response during a power System disturbance. Analyses of system disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations helps determine the interruption of flows during the disturbances. Recording of at least one IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus helps analysis of IBR Unit performance during BES disturbances that do not operate the interconnecting circuit breaker. One IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus is specified because it may be the most challenging location for IBR Unit to continue to ride-through during BES disturbance. For IBR Unit in commercial operation prior to the effective date of this standard, SER data is required, if IBR Unit is capable of recording.

Rationale for Requirement R2

The intent is to capture sufficient FR data for Elements at each IBR generating facility to analyze the overall response of the IBR generating facility to a system disturbance. Analyses of disturbances involving widespread reduction of power output from IBRs in recent years has shown that expansion of monitoring at IBR sites is necessary. The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g., residual or neutral current if the phase currents are directly measured).

The plant level FR measurements, i.e., measured on high-side terminals of the main power transformer, specified in Requirement R2, Part 2.1 provide data at the IBR generating facility interconnection to the bulk power system. To cover all possible fault types, phase-to-neutral voltage recording for each phase is required to be determinable. Each phase current and residual current are required to distinguish between phase faults and ground faults. This data also facilitates determination of the fault location and cause of relay operation. The measurements of active and reactive power provide data on the overall generating facility's response to the system disturbance.

Analyses of system disturbances involving widespread reduction of real power output from IBRs in recent years have shown that all individual IBR Units within the IBR generating facility do not react to the disturbance identically because of their wide geographic distribution. Requirement R2, Part 2.2 requires monitoring of at least one IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus, ensuring that FR data is available to analyze individual IBR Unit response. It may be challenging to record/determine specified electrical quantities from IBR Unit terminals for existing installations. As such, the standard allows for recording/determining specified electrical quantities on high-side of IBR Unit transformer.

In some cases, the dynamic reactive device is used within the IBR generating facility and often connected to medium voltage collector bus. Regardless of where dynamic reactive device is connected, the output of it during system disturbances is important to understand overall performance of the plant during a disturbance. The measured or determined electrical quantities for dynamic reactive device are same as those specified to be measured/determined from high-side of main power transformer.

Recording of Electrical Quantities

For effective fault analysis, it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation. FR also shows generator output response to a system disturbance.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120 degrees, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current Ir, is calculated as a sum of vectors of three phase currents:

$$\mathbf{I}_r = 3\bullet\mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable Elements as outlined in Requirement

R2.

Rationale for Requirement R3

Time stamped pre- and post-trigger FR data aid in the analysis of power system operations and determination if operations were as intended.

The “Odessa Disturbance” report from September 2021 recommended high resolution oscillography data at the point of interconnection and on individual IBR Units. The minimum recording rate of 64 samples per cycle is specified recognizing state-of-the-art for DME including storage any storage capability limitations and provides sufficient data to recreate accurate response of the IBR generating facility to system disturbances. This higher sampling rate is particularly important for capturing transient events at the individual IBR Units.

Pre- and post-trigger fault data along with the SER data, all time stamped to a common clock, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Additionally, IBR Units employ fast acting control systems (with built in protection functions) dictating IBR generating facility’s response to system disturbance. The FR data from IBR Units time stamped to a common clock is necessary to analyze IBR Unit and generating facilities’ response to system disturbances. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles. To capture the full response of IBR generating facility spread over a large geographic area, a 2 second total minimum record length synchronized to a common clock is necessary for FR data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data but are not capable of providing fault data in a single record with 120 contiguous cycles total.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R3, Part 3.1.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R3, sub-Part 3.1.3.2 specifies a phase overvoltage or undervoltage trigger during voltage ride-through events. For IBR Unit FR data triggers, Requirement R3, Part 3.2.3.1 specifies a phase overvoltage and undervoltage. Requirement R3, sub-Part 3.2.3.2 specifies a trigger for overfrequency and underfrequency to record response during frequency ride-through events.

The triggers specified in Requirement R3, Part 3.3 for dynamic reactive device FR data are similar to ones specified in Requirement R3, Part 3.1 for plant level FR data measured or determined on high-side of the main power transformer.

Rationale for Requirement R4

Large scale system disturbances generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and IBR generating facility’s response to large scale system disturbances. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event. The state-of-the-art DDR equipment is capable of continuous recording.

DDR data contains the dynamic response of the IBR generating facility to a system disturbance and is used for analyzing complex power system events. This recording is typically used to capture short-term and long-term disturbances. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

DDR is used to measure transient response to system disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage and current from the same phase or positive sequence for each applicable main power transformer for analysis. It is also sufficient to provide a single frequency for any of the provided voltages since all main power transformers within an IBR generating facility are at the same frequency. Recording of all three phases of voltage/current is not required, although this may be used to compute and record the positive sequence value(s). The electrical quantities for Real Power and Reactive Power on a three-phase basis can be measured/recorded or determined (calculated, derived, etc.).

The data requirements for PRC-028-1 are based on a system configuration assuming all normally closed circuit breakers on a BES bus are closed.

A crucial part of disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary to have DDR on the high-side of the main power transformer(s) measuring the specified electrical quantities to adequately capture IBR generating facility's response.

The Requirement R4, Part 4.1 requires either one phase-to-neutral or positive sequence voltage. However, the phase-to-phase voltage recording is acceptable. Since the BES operates under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Rationale for Requirement R5

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltages and frequency. The input sampling rate specified is same as the one specified in the Reliability Standard PRC-002.

An output recording rate of electrical quantities of at least 60 times per second refers to the recording rate of the device. Recorded measurements of at least 60 times per second provide adequate recording speed to monitor the IBR generating facility's response during power system disturbances. Since the control system associated with IBRs is fast acting, higher frequency recording is necessary to accurately reconstruct events. An output recording rate of 60 times per second provides this higher frequency recording while not greatly increasing data storage requirements.

Rationale for Requirement R6

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 1 millisecond accuracy. However, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 1 millisecond accuracy will suffice with respect to providing time synchronized data. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. Note that the recently published IEEE Std 2800 requires the DME recording plant level data be synchronized to the clock with accuracy of ± 1 microsecond accuracy. However, the accuracy requirement is set to ± 1 millisecond to strike a balance between need of accuracy and practical limitations of equipment necessary to achieve the stated accuracy.

The IBRs, which are not affected by inertial time constants, make changes in power production very rapidly. To understand and analyze control decisions during system disturbances and the reasons behind them over dozens of plants with possibly 100's of IBR Units requires a high level of accurate time synchronization. Following provide some examples of IBR's fast response:

- Typical 90% response to a three-phase fault is <40 ms.
- Central power plant controllers issue updated commands in as little as 40 ms upon detection of change in system conditions.
- Standard closed loop voltage control response can be <200 ms.
- Instantaneous Inverter protective trip decisions such as AC or DC overvoltage or reverse DC current can be made in less than 10 ms.

Rationale for Requirement R7

Requirement R7, Part 7.1 specifies a minimum time period of 20 calendar days inclusive of the day the data was recorded for which the data is to be retrievable. Data hold requests are usually initiated the same or next day following a major event, however, it takes a longer time to determine which data from which generating facility needs to be retrieved for event analysis. A 20-calendar day time period provides enough time for communication between various Entities regarding the event and need for data retrieval from DME at various generating facilities. The requestor of data has to be aware of 20-calendar day retrievability limit to ensure timely data hold requests. Requiring data retention for a longer period of time is expensive and unnecessary.

With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 20 days. To clarify the 20-calendar day time frame, let's assume that event occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 20 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 21, that is outside the 20 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER, FR, and DDR data for generating facilities as per the applicability. To facilitate the analysis of system disturbances, it is important that the data is provided to the requestor within a reasonable time. Providing the data within 30 calendar days (or the granted extension time), subject to Requirement R7, Part 7.2, allows for reasonable time to collect the data and perform any necessary computations or formatting. An entity may request an extension of the 30 calendar days submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Disturbance analysis includes reviewing data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improve timely analysis. The formatting and naming convention requirements for SER, FR, and DDR are consistent with same requirements in the Reliability Standard PRC-002.

SER data: Requirement R7, Part 7.3 specifies a simple ASCII Comma Separated Value (CSV) format according to Attachment 1. It is necessary to establish a standard format as it allows data submitted by one entity or facility to be incorporated with same data provided by other entities or facilities to develop a detailed sequence of events timeline of a power system disturbance.

FR and DDR data: Requirement R7, Part 7.4 specifies either CSV format or the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the FR and DDR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources. The 2013 revision of the IEEE C37.111 includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R7, Part 7.5 specifies the IEEE C37.232 Standard for Common Format for Naming Time Sequence Data Files (COMNAME) format for naming the SER, FR, and DDR data files. The lack of a common naming practice seriously hinders the event analysis and investigation process.

Rationale for Requirement R8

The standard requires that Entity restore the recording capability for SER, FR, or DDR data within 90 calendar days of the discovery of a failure. The 90 calendar day time period permitted in this requirement strikes a balance between reasonable time needed to restore capability while ensuring that recording capability is not out of service for an extended duration. If the recording capability cannot be restored within 90 calendar days due to limitations such as budget cycle, service crews, vendors, needed outages, etc., the entity is required to submit a Corrective Action Plan for restoring the recording capability to the Regional Entity and implement it. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored Element does not constitute a failure of the disturbance monitoring capability.

Rationale for Requirement R9

For Facilities in commercial operation on or before the effective date of PRC-028-1, the Implementation Plan requires applicable Entities to be fully compliant at 50% of their Facilities within three (3) calendar years of the effective date of PRC-028-1 and fully compliant at 100% of Facilities prior to January 1, 2030. The Implementation Plan recognizes Federal Energy Regulatory Commission's directive, under Order No. 901[3], to have this standard effective and enforceable before 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Requirement R9, Parts 9.1 through 9.5 outlines details to be included in the Corrective Action Plan.

[3] See Order No. 901 at P226.

Technical Rationale for Reliability Standard PRC-028-1

March ~~2023~~ 2024

PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter Based Resources

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for ~~inverter-based resources~~Inverter-Based Resources[1] (IBRs) to aid with event analysis, performance monitoring, and disturbance-based IBR generating facility model validation. These disturbance reports recommended to install disturbance monitoring equipment (DME) at wind and solar photovoltaic (PV) resources to ensure adequate data is available for event analysis, performance monitoring, and validating IBR generating facility models. The recommendation included plant-level high resolution oscillography data, plant SCADA data with a resolution of one second, sequence of events recording for all IBR ~~units~~Units[2] that include all fault codes, and at least one IBR ~~unit~~ Unit on each collector feeder configured to capture high resolution oscillography data within the IBR ~~unit~~Unit.

The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. The recent disturbance analyses of events involving IBRs (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have demonstrated that IBR's response to a normally cleared few cycle fault is undesirable and poses risk to system reliability. All these disturbance analyses have identified that IBRs involved did not have sufficient monitoring data to understand the plants' responses. The initiating event, e.g., a normally cleared transmission fault, was not a large-scale system disturbance; however, IBR plant's undesirable response due to a system fault resulted in a larger system disturbance. Adequate monitoring data is required to understand IBR plant's performance. Most of the IBRs involved in these disturbances did not have and were not required to have adequate disturbance monitoring data. The lack of disturbance monitoring data available from these facilities led to difficulty in adequately assessing the events. Introducing IBR monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-

[1] Inverter-Based Resource as of 02/22/2024: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell. **(This footnote will be removed when IBR definition is finalized)**

[2] IBR Unit as of 02/23/2024: An individual device that uses a power electronic interface, such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connects at a single point on the collector system; or a grouping of multiple devices that uses a power electronic interface(s), such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connect together at a single point on the collector system. **(This footnote will be removed when IBR Unit definition is finalized)**~~IBR unit includes the inverter, wind turbine generator etc.~~

Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for IBRs is created instead of revising the Reliability Standard PRC-002.

The Transmission Owners and Generator Owners, as applicable, will have the responsibility for ensuring that adequate data is available for applicable Elements at the applicable IBR generating facilities. This standard requires that sequence of events recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data is available from the applicable IBR generating facilities.

Rationale for Applicability Section
Functional Entities
The two functional entities that are responsible for implementing disturbance monitoring equipment and collecting recording data are: Generator Owner and Transmission Owner. The standard is only applicable to Transmission Owner in case where Transmission Owner owns equipment (e.g., circuit breaker(s), main step-up transformer, collector bus, dynamic reactive device, etc.) within the IBR Plant.

Applicable Facilities
~~The following facilities from the BES definition are in the scope of this standard:~~
~~Inverter-based portion of generating plant/Facility meeting the criterion set by Inclusion I2, part (b)~~
~~Generating plant/Facility meeting the criteria set by Inclusion I4~~
The BES Inverter-Based Resources and Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV are in the scope of this standard.

Order No. 901 directed NERC to develop Reliability Standards "to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment." Order No. 901 at P 85. FERC continued, "We further agree with the findings in NERC reports (e.g., a lack of high-speed data captured at the IBR or plant-level controller and low-resolution time stamping of inverter sequence of event recorder information has hindered event analysis) and direct NERC through its standard development process to address these findings."

In distinguishing among the different types of IBRs and their registration status that must be covered by the standards, FERC stated: "Where necessary to describe our directives, however, we differentiate between IBRs registered with NERC (or which will be registered pursuant to the Commission's directives in *Registration of Inverter-based Resources*, 181 FERC ¶ 61,124 (2022) (IBR Registration Order)) and therefore subject to the Reliability Standards (i.e., registered IBR), IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards (i.e., unregistered IBRs), and IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk-Power System (i.e., IBR-DER)." Order No. 901 at n. 14.

In proposed PRC-028-1, the standard drafting team includes both categories of generation that would be registered under proposed changes to NERC Rules of Procedure consistent with Order No. 901. In February 2024, the NERC Board of Trustees approved revisions to the Rules of Procedure to expand the Generator Owners and Generator Operators registered with NERC for compliance purposes. In addition to owners and operators of generating Facilities, NERC will register owners and operators of sub-BES IBRs meeting the following criteria: non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. More information on these changes, which are pending FERC approval, are available at: https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board%20Open%20 Agenda%20Package%20-%20February%2022%202024_ATTENDEE.pdf [nerc.com]

The standard drafting team understands that NERC will initiate a separate *Glossary* revision effort to revise the definition of Generator Owner and Generator Operator consistent with the proposed Rules of Procedure definitions for registration. This effort will complete well in advance of the team's proposed [X] year implementation plan for Reliability Standard PRC-028-1.

The following Elements associated with ~~BES generating plants~~~~i~~Inverter-~~b~~Based ~~r~~Resources noted above are in the scope of this standard:

- Circuit breaker(s)
- Main power transformer(s)
- Collector bus
- Shunt static or dynamic reactive device(s)
- At least one IBR ~~u~~Unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus~~At least one IBR unit connected to last 10% of each collector feeder length (i.e., furthest from the collector bus)~~

The following examples are provided to clarify applicability of the PRC-028 standard.

Example 1: Applicability of PRC-028

Figure 1 shows a typical single line diagram of an IBR generating facility. The IBR generating facility is connected to the transmission system via a short tie-line. The length of collector feeder #1, #2, and #3 is 3000 ft, 2500 ft, and 2800 ft respectively. ~~IBR unit~~IBR Units #6 and #7 are connected to collector feeder #1 at 2800 ft and 3000 ft distance from the collector bus respectively. ~~IBR unit~~IBR Unit #18 is connected to collector feeder #3 at 2800 ft distance from the collector bus. ~~In other words, these IBR units are connected to last 10% of the collector feeder #1.~~ In other words, these ~~IBR unit~~IBR Units #6, #7 and #18 are connected at a distance ≥ 90% of the longest collector feeder from the collector bus. This IBR generating facility is equipped with a dynamic reactive device (e.g., synchronous condenser, static VAR compensator etc.) connected to the collector bus.

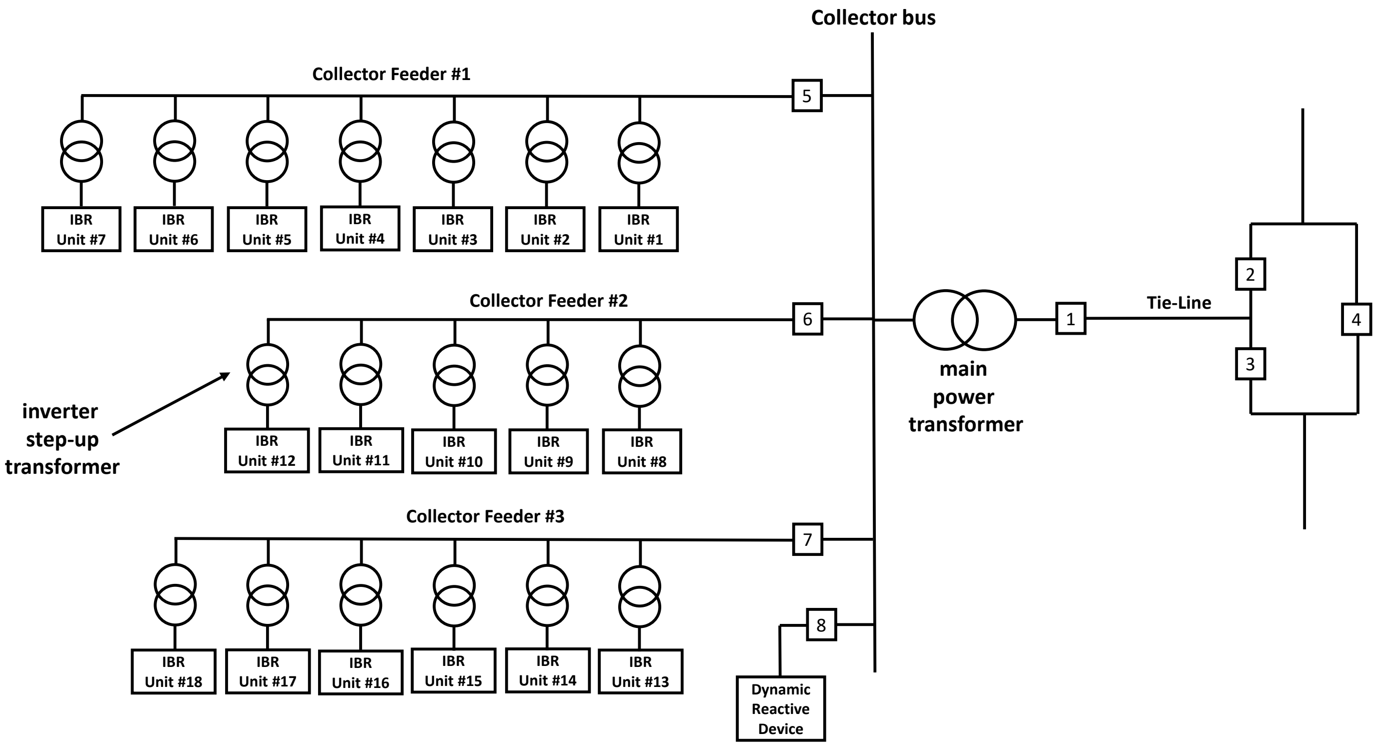


Figure 1: Typical IBR Generating Facility Single Line Diagram

SER Data: The SER data is required for circuits breaker 1, 5, 6, 7, and 8. Circuit breaker 1 is associated with the main power transformer. Circuit breakers 5, 6, 7, and 8 are associated with the collector bus. The SER data for ~~either IBR unit~~IBR Unit #6, ~~or~~ #7, or #18 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus~~both are connected to last 10% of the collector feeder #1 length~~. ~~Similarly, at least one IBR unit connected to last 10% of collector feeder #2 and #3 is also required to have SER data.~~

FR Data: The FR data is required from high side terminals of the main power transformer. In this example, the IBR plant consists of only one main power transformer. If the IBR plant consists of more than one main power transformer, then FR data for each main power transformer is required. The FR data for ~~either IBR unit~~IBR Unit #6, ~~or~~ #7, or #18 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus ~~both are connected to last 10% of the collector feeder #1 length~~. ~~Similarly, at least one IBR unit connected to last 10% of collector feeder #2 and #3 is also required to have FR data.~~ As the IBR plant is equipped with the dynamic reactive device, the FR data for it also required.

DDR Data: The DDR data is required from high side terminals of the main power transformer. If the IBR plant consists of more than one main power transformer, then DDR data for each main power transformer is required. The DDR data from individual ~~IBR unit~~IBR Units is not required.

Example 2: Applicability of PRC-028 (Facility with two collector buses and main power transformers)

Figure 2 shows a ~~typical~~ single line diagram of an IBR generating facility with two collector buses and main power transformers. The IBR generating facility is connected to the transmission system via a short tie-line. The collector feeders #1 and #2 are connected to collector bus #1. The collector feeders #3 and #4 are connected to collector bus #2. The length of collector feeder #1, #2, #3, and #4 is 3000 ft, 2500 ft, 2800 ft, and 2600 ft respectively. The collector feeder #1 is the longer of two collector feeders connected to collector bus #1. IBR Units #6 and #7 are connected to collector feeder #1 at 2800 ft and 3000 ft distance from the collector bus #1 respectively. IBR Unit #12 is connected to collector feeder #2 at 2500 ft from the collector bus #1. The IBR Units #6 and #7 are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #1. The collector feeder #3 is the longer of two collector feeders connected to collector bus #2. IBR Units #17 and #18 are connected to collector feeder #3 at 2600 ft and 2800 ft distance from the collector bus #2 respectively. IBR Unit #23 is connected to collector feeder #4 at 2600 ft from the collector bus #2. The IBR Units #17, #18, and #23 are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #2.

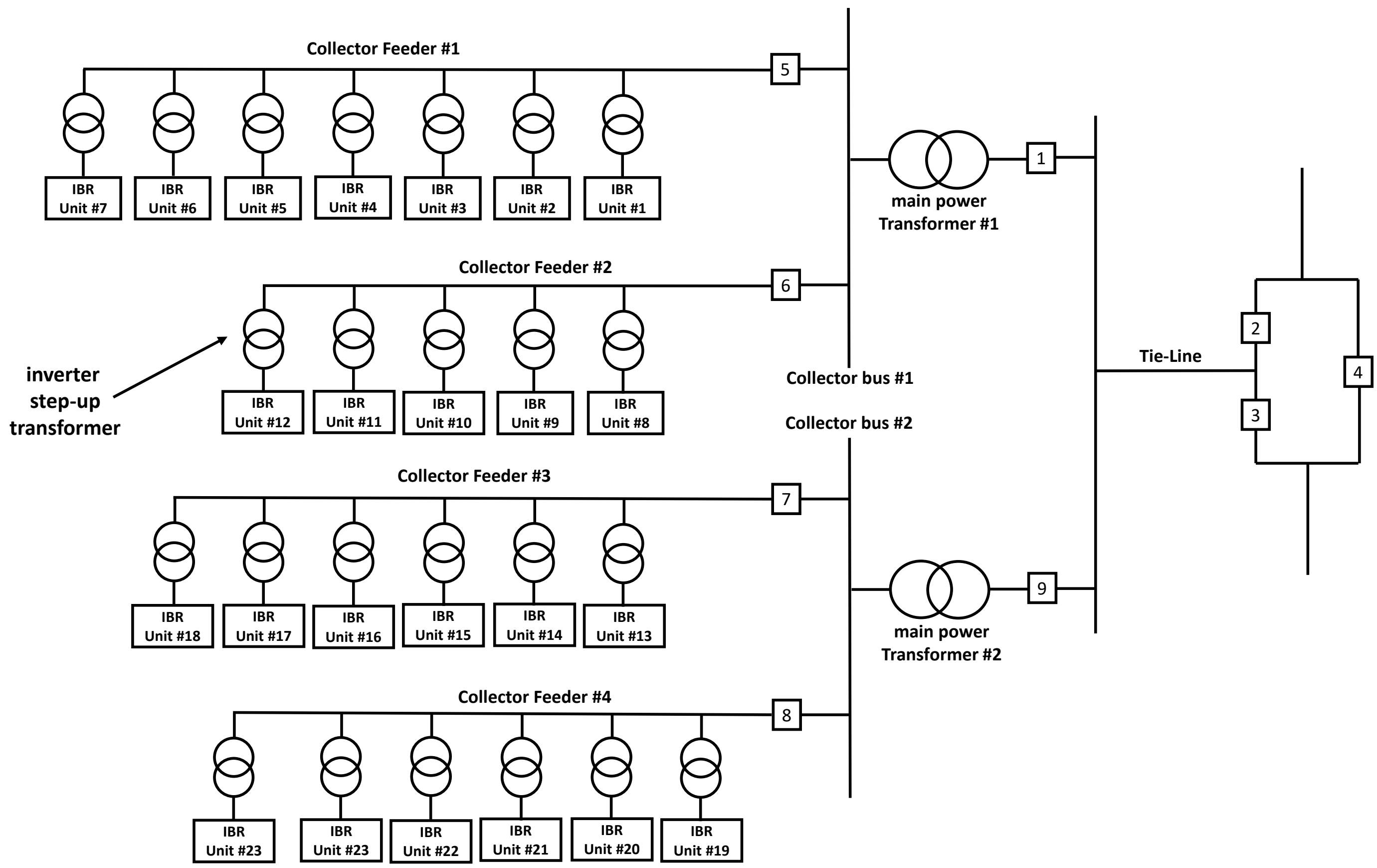


Figure ~~1~~2: Typical IBR Generating Facility with two collector buses and main power transformers

SER Data: The SER data is required for circuits breaker 1, 5, 6, 7, 8 and 9. Circuit breakers 1 and 9 are associated with main power transformers. Circuit breakers 5, 6, 7, and 8 are associated with collector buses #1 and #2. The SER data for IBR Unit #6 or #7 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #1. The SER data for IBR Unit #17, #18, or #23 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #2.

FR Data: The FR data is required from high side terminals of both main power transformers. The SER data for IBR Unit #6 or #7 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #1. The SER data for IBR Unit #17, #18, or #23 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #2.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example ~~2~~3: Applicability of PRC-002 versus PRC-028

Figure ~~2~~ 3 shows an example of IBR interconnection to the transmission system via Line 34. The BES bus in substation Wu is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for the identified BES bus are per the requirements in the Reliability Standard PRC-002. The IBR generating facility in this example meets the criteria set by inclusion I2 of the BES definition. Hence, the Reliability Standard PRC-028 is applicable to the IBR generating facility.

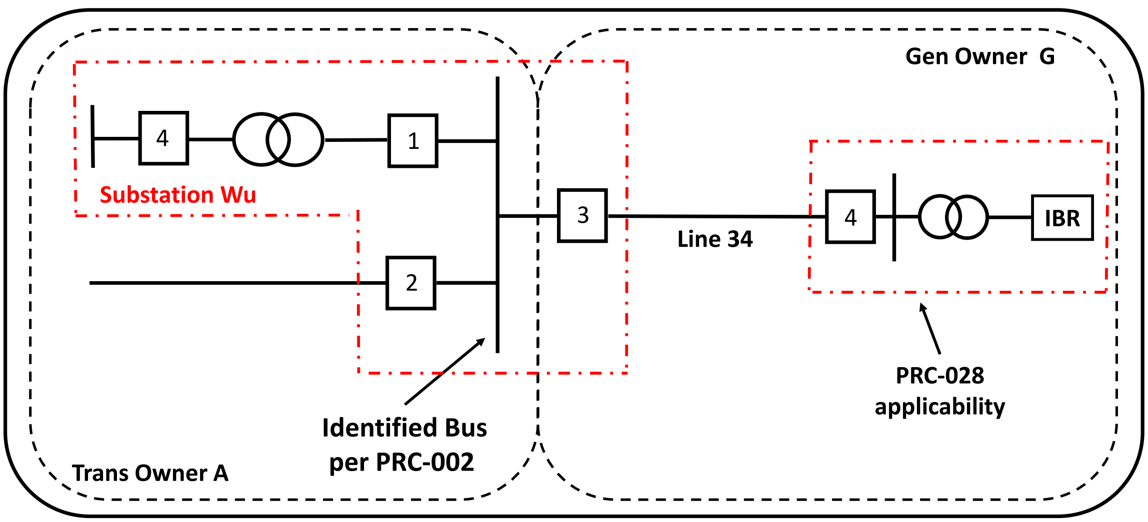


Figure ~~2~~3: IBR Interconnection – Applicability of PRC-002 versus PRC-028

Example ~~3~~4: Transmission Owner owned Equipment within the IBR generating facility

Figure ~~3~~ 4 shows an example of an IBR interconnection where Transmission Owner A owns circuit breaker 3 associated with an IBR generating facility. In this case, Transmission Owner A is responsible for SER data for circuit breaker 3. It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an IBR generating facility. However, in cases where this is true, Transmission Owner is responsible for SER, FR, and DDR data, as applicable, required by the Reliability Standard PRC-028.

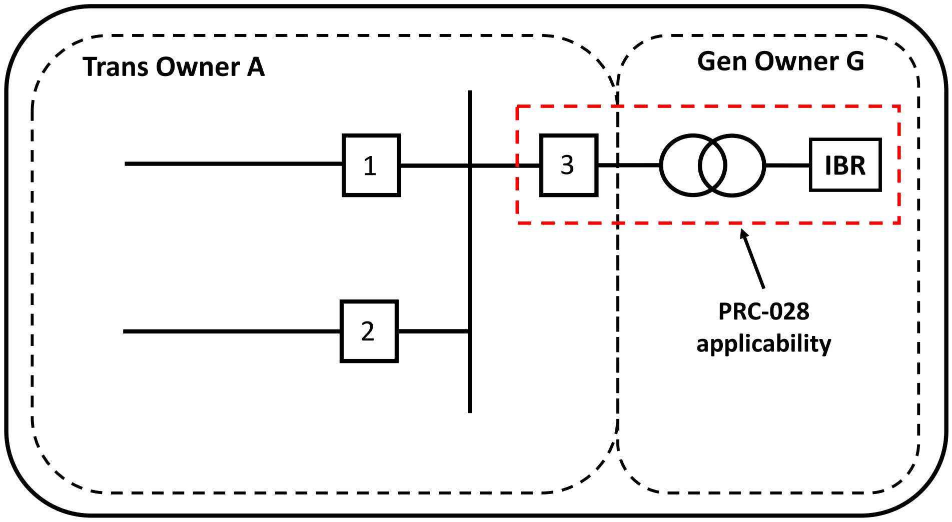
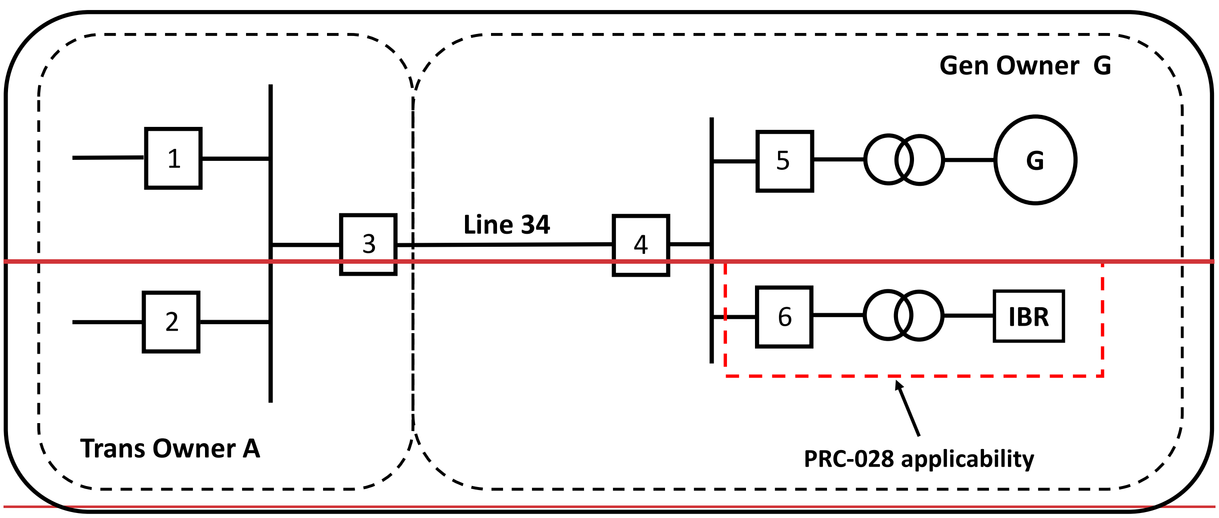


Figure ~~3~~4: Transmission Owner owned Equipment within an IBR Plant

~~**Example 4: Hybrid Plant (synchronous machine + IBR)**~~

~~Figure 4 shows an example of a hybrid plant, i.e., synchronous machine + IBR, interconnecting to the transmission system via Line 34. The aggregate nameplate rating of this hybrid generating facility is greater than 75 MVA and meets the criteria set by inclusion I2, part (b) of the BES definition. The SER, FR, and DDR data for inverter-based portion of this hybrid generating facility is required.~~



~~Figure 4: Hybrid Generating Facility~~

Rationale for Requirement R1

The standard requires to capture SER data from circuit breakers and ~~IBR unit~~IBR Units within the IBR generating facility. At least one ~~IBR unit~~IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus ~~to last 10% of each collector feeder length~~ must have the data specified in R1, Part 1.2 and Part 1.3.~~.1 through 1.2.6~~

Change of state of circuit breaker position and ~~IBR unit~~IBR Unit data, time stamped according to Requirement R7 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of IBR generating facility's response during a power System disturbance. Analyses of system disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations helps determine the interruption of flows during the disturbances. Recording of at least one ~~IBR unit~~IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus ~~connected to last 10% of each collector feeder length~~ helps analysis of ~~IBR unit~~IBR Unit performance during BES disturbances that do not operate the interconnecting circuit breaker. One ~~IBR unit~~IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus ~~in the last 10% of the collector feeder length~~ is specified because it may be the most challenging location for ~~IBR unit~~IBR Unit~~s~~ to continue to ride-through during BES disturbance. For IBR Unit in commercial operation prior to the effective date of this standard, SER is data is required, if IBR Unit is capable of recording.

Rationale for Requirement R2

The intent is to capture sufficient FR data for Elements at each IBR generating facility to analyze the overall response of the IBR generating facility to a system disturbance. Analyses of disturbances involving widespread reduction of power output from IBRs in recent years has shown that expansion of monitoring at IBR sites is necessary. The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured).

The plant level FR measurements, i.e., measured on high-side terminals of the main power transformer, specified in Requirement R2, Part 2.1 provide data at the IBR generating facility interconnection to the bulk power system. To cover all possible fault types, phase-to-neutral voltage recording for each phase is required to be determinable. Each phase current and residual current are required to distinguish between phase faults and ground faults. This data also facilitates determination of the fault location and cause of relay operation. The measurements of active and reactive power provide data on the overall generating facility's response to the system disturbance.

Analyses of system disturbances involving widespread reduction of real power output from IBRs in recent years have shown that all individual ~~IBR unit~~IBR Units within the IBR generating facility do not react to the disturbance identically because of their wide geographic distribution. ~~The choice of at least one IBR unit connected to the last 10% of each collector feeder length in Requirement R2, Part 2.2 requires monitoring on a selection from some of the most geographically remote IBR units at each site, ensuring that FR data is available to analyze individual IBR unit response.~~ Requirement R2, Part 2.2, requires monitoring of at least one IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus, ensuring that FR data is available to analyze individual IBR Unit response. It may be challenging to record/determine specified electrical quantities from ~~IBR unit~~IBR Unit terminals for existing installations. As such, the standard allows for recording/determining specified electrical quantities on high-side of ~~IBR unit~~IBR Unit transformer.

In some cases, the dynamic reactive device is used within the IBR generating facility and often connected to medium voltage collector bus. Regardless of where dynamic reactive device is connected, the output of it during system disturbances is important to understand overall performance of the plant during a disturbance. The measured or determined electrical quantities for dynamic reactive device are same as those specified to be measured/determined from high-side of main power transformer.

Recording of Electrical Quantities

For effective fault analysis, it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation. FR also shows generator output response to a system disturbance.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120 degrees, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current Ir, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable Elements as outlined in Requirement R2.

Rationale for Requirement R3

Time stamped pre- and post-trigger FR data aid in the analysis of power system operations and determination if operations were as intended.

The "Odessa Disturbance" report from September 2021 recommended high resolution oscillography data at the point of interconnection and on individual ~~IBR unit~~IBR Units. The minimum recording rate of ~~128~~64 samples per cycle is specified recognizing state-of-the-art for DME including storage any storage capability limitations and provides sufficient data to recreate accurate response of the IBR generating facility to system disturbances. This higher sampling rate is particularly important for capturing transient events at the individual ~~IBR unit~~IBR Units.

Pre- and post-trigger fault data along with the SER data, all time stamped to a common clock, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Additionally, ~~IBR unit~~IBR Units employ fast acting control systems (with built in protection functions) dictating IBR generating facility's response to system disturbance. The FR data from ~~IBR unit~~IBR Units time stamped to a common clock is necessary to analyze ~~IBR unit~~IBR Unit and generating facilities response to system disturbances. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles. To capture the full response of IBR generating facility spread over a large geographic area, a 2 second total minimum record length synchronized to a common clock is necessary for FR data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data but are not capable of providing fault data in a single record with 120 contiguous cycles total.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R3, Part 3.1.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R3, sub-Part 3.1.3.2 specifies a phase overvoltage or undervoltage trigger during voltage ride-through events. For ~~IBR unit~~IBR Unit FR data triggers, Requirement R3, Part 3.2.3.1 specifies a phase overvoltage and undervoltage. ~~Requirement R3, Part 3.2.3.2 specifies a trigger for DC overvoltage, DC overcurrent, and DC reverse overcurrent to monitor for abnormal DC quantities at the IBR unitIBR Unit resulting from system disturbances.~~ Requirement R3, sub-Part 3.2.3.2~~3~~ specifies a trigger for overfrequency and underfrequency to record response during frequency ride-through events.

The triggers specified in Requirement R3, Part 3.3 for dynamic reactive device FR data are similar to ones specified in Requirement R3, Part 3.1 for plant level FR data measured or determined on high-side of the main power transformer.

Rationale for Requirement R4

Large scale system disturbances generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and IBR generating facility's response to large scale system disturbances. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event. The state-of-the-art DDR equipment is capable of continuous recording.

DDR data contains the dynamic response of the IBR generating facility to a system disturbance and is used for analyzing complex power system events. This recording is typically used to capture short-term and long-term disturbances. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

DDR is used to measure transient response to system disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage and current from the same phase or positive sequence for each applicable main power transformer for analysis. It is also sufficient to provide a single frequency for any of the provided voltages since all main power transformers within a IBR generating facility are at the same frequency. Recording of all three phases of voltage/current is not required, although this may be used to compute and record the positive sequence value(s). The electrical quantities for Real Power and Reactive Power on a three-phase basis can be measured/recorded or determined (calculated, derived, etc.).

The data requirements for PRC-028-1 are based on a system configuration assuming all normally closed circuit breakers on a BES bus are closed.

A crucial part of disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary to have DDR on high-side of the main power transformer(s) measuring the specified electrical quantities to adequately capture IBR generating facility’s response.

The Requirement R4, Part 4.1 requires either one phase-to-neutral or positive sequence voltage. However, the phase-to-phase voltage recording is acceptable. Since the BES operates under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Rationale for Requirement R5

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltages and frequency. The input sampling rate specified is same as one specified in the Reliability Standard PRC-002.

An output recording rate of electrical quantities of at least 60 times per second refers to the recording rate of the device. Recorded measurements of at least 60 times per second provide adequate recording speed to monitor the IBR generating facility’s response during power system disturbances. Since control system associated with IBRs is fast acting, higher frequency recording is necessary to accurately reconstruct events. An output recording rate of 60 times per second provides this higher frequency recording while not greatly increasing data storage requirements.

Rationale for Requirement R6

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 1~~00~~ milli~~cro~~second accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 1~~00~~ milli~~cro~~second accuracy will suffice with respect to providing time synchronized data. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. Note that the recently published IEEE Std 2800 requires the DME recording plant level data be synchronized to the clock with accuracy of ± 1 microsecond accuracy; however, the accuracy requirement is set to ± 1~~00~~ milli~~cro~~second to strike a balance between need of accuracy and practical limitations of equipment necessary to achieve the stated accuracy.

The IBRs, which are not affected by inertial time constants, make changes in power production very rapidly. To understand and analyze control decisions during system disturbances and the reasons behind them over dozens of plants with possibly 100's of ~~IBR unit~~IBR Units requires a high level of accurate time synchronization. Following provide some examples of IBR's fast response:

- Typical 90% response to a three-phase fault is <40 ms.
- Central power plant controllers issue updated commands in as little as 40 ms upon detection of change in system conditions.
- Standard closed loop voltage control response can be <200 ms.
- Instantaneous Inverter protective trip decisions such as AC or DC overvoltage or reverse DC current can be made in less than 10 ms.

Rationale for Requirement R7

Requirement R7, Part 7.1 specifies a minimum time period of ~~3~~20 calendar days inclusive of the day the data was recorded for which the data to be retrievable. Data hold requests are usually initiated the same or next day following a major event, however, it takes a longer time to determine which data from which generating facility needs to be retrieved for event analysis. A ~~3~~20 calendar day time period provides enough time for communication between various Entities regarding the event and need for data retrieval from DME at various generating facilities. The requestor of data has to be aware of ~~3~~20 calendar day retrievability limit to ensure timely data hold requests. Requiring data retention for a longer period of time is expensive and unnecessary.

With the state-of-the-art equipment, having the data retrievable for the ~~3~~20 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than ~~3~~20 days. To clarify the ~~3~~20 calendar day time frame, let's assume that event occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within ~~3~~20 calendar days after a request or a granted time extension. However, if a request for the data is made on Day ~~3~~21, that is outside the ~~3~~20 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER, FR and DDR data for generating facilities as per the applicability. To facilitate the analysis of system disturbances, it is important that the data is provided to the requestor within a reasonable time. Providing the data within 30 calendar days (or the granted extension time), subject to Requirement R7, Part 7.2, allows for reasonable time to collect the data and perform any necessary computations or formatting. An entity may request an extension of the 30 calendar days submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Disturbance analysis includes reviewing data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis. The formatting and naming convention requirements for SER, FR, and DDR are consistent with same requirements in the Reliability Standard PRC-002.

SER data: Requirement R7, Part 7.3 specifies a simple ASCII Comma Separated Value (CSV) format according to Attachment 1. It is necessary to establish a standard format as it allows data submitted by one entity or facility to be incorporated with same data provided by other entities or facilities to develop a detailed sequence of events timeline of a power system disturbance.

FR and DDR data: Requirement R7, Part 7.4 specifies either CSV format or the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the FR and DDR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources.~~It is necessary to specify a standard format as multiple submissions of data from many sources is typically incorporated to provide a detailed analysis of a power system disturbance.~~ The 2013 revision of the IEEE C37.111 includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R7, Part 7.5 specifies the IEEE C37.232 Standard for Common Format for Naming Time Sequence Data Files (COMNAME) format for naming the SER, FR and DDR data files. The lack of a common naming practice seriously hinders the event analysis and investigation process.

Rationale for Requirement R8

The standard requires that Entity restore the recording capability for SER, FR, or DDR data within 90 calendar days of the discovery of a failure. The 90 calendar day time period permitted in this requirement strikes a balance between reasonable time needed to restore capability while ensuring that recording capability is not out of service for an extended duration. If the recording capability cannot be restored within 90 calendar days due to limitations such as budget cycle, service crews, vendors, needed outages, etc., the entity is required to submit a Corrective Action Plan for restoring the recording capability to the Regional Entity and implement it. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored Element does not constitute a failure of the disturbance monitoring capability.

Rationale for Requirement R9

For Facilities in commercial operation on or before the effective date of PRC-028-1, the Implementation Plan requires applicable Entities to be fully compliant at 50% of their Facilities within three (3) calendar years of the effective date of PRC-028-1 and fully compliant at 100% of Facilities prior to January 1st, 2030. The Implementation Plan recognizes Federal Energy Regulatory Commission's directive, under Order No. 901[3], to have this standard effective and enforceable before 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design,

[3] See Order No. 901 at P226.

schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Requirement R9, Parts 9.1 through 9.5 outlines details to be included in the Corrective Action Plan.

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Open through April 11, 2024

Now Available

A 25-day formal comment period for **Project 2021-04 Modifications to PRC-002 - Phase II** is open through **8 p.m. Eastern, Thursday, April 11, 2024** for the following standards and implementation plan:

- PRC-002-5 – Disturbance Monitoring and Reporting Requirements
- PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- Implementation Plan

The standard drafting team's considerations of the responses received from the previous comment period are reflected in these drafts of the standards.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact **ballotadmin@nerc.net** to assist with the removal of any duplicate registrations.

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
Additional ballots for the standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 2 - 11, 2024**.

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 2021-04 Modifications to PRC-002 observer list” 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:	2021-04 Modifications to PRC-002 – Phase II | Draft 2
Comment Period Start Date:	3/18/2024
Comment Period End Date:	4/11/2024
Associated Ballots:	2021-04 Modifications to PRC-002 – Phase II Implementation Plan AB 2 OT 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 | Non-Binding Poll AB 2 NB 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 AB 2 ST 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll AB 2 NB 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 AB 2 ST

There were 73 sets of responses, including comments from approximately 173 different people from approximately 115 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1, Do you agree with the modification in "Applicability, Section 4.2. Facilities" in PRC-002-5 and PRC-028-1?

2. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

3. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

4. Do you agree with introduction of Requirement R9 in PRC-028-1 requiring Entities of an applicable facility that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance to develop, maintain, and implement a Corrective Action Plan?

5. 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
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO

					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Southern Company - Alabama Power Company	Colby Galloway	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	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
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
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
					Kris Carper	Arizona Electric Power Cooperative, Inc.	2	WECC
					Jason Procuniar	Buckeye Power, Inc.	4	RF

					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Scott Berry	Wabash Valley Power Association	3	RF
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Jasmine Morris	Southern Maryland Electric Cooperative	3	RF
Eversource Energy	Joshua London	1,3		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Electric Reliability Council of Texas, Inc.	Kennedy Meier	2		ISO/RTO Council Standards Review Committee (SRC)	Darcy O'Connell	California ISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Joshua Phillips	Southwest Power Pool, Inc. (RTO)	2	MRO
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Thomas Foster	PJM Interconnection, L.L.C.	2	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
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
					Tyler Brun	Pacific Gas and Electric Company	5	WECC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC

					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	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
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	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
					Joshua London	Eversource Energy	1	NPCC
Elevate Energy Consulting	Ryan Quint	NA - Not Applicable	NA - Not Applicable	Elevate Energy Consulting	Ryan Quint	Elevate Energy Consulting		NA - Not Applicable
					N/A	N/A		NA - Not Applicable
Ryan Strom	Ryan Strom		RF	Buckeye Power Group	Carl Spaetzel	Buckeye Power, Inc.	3	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Zemanek	Buckeye Power, Inc.	5	RF
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Stephen Whaite	Stephen Whaite		RF	ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC

					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1, Do you agree with the modification in “Applicability, Section 4.2. Facilities” in PRC-002-5 and PRC-028-1?	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	No
Document Name	
Comment	
The applicability section of PRC-028-1 uses “BES” and then “Non-BES” and it is unclear why the SDT could not simply say Registered IBR, since the section is essentially duplicating the definition of Registered IBR pursuant to the changes in the ROP. Furthermore, the language does not appear to exactly match those changes and uses the phrase “that either have or contribute to an aggregate…” which seems vague. Therefore, we recommend developing a more straightforward and effective approach to defining this applicability rather than slightly modifying and using redundant language as compared to the ROP.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports and recommends implementation of EEI provided comments. Additionally, Duke Energy recommends changing PRC-028-1 Applicability - 4.2 from "a voltage greater than or equal to 60 kV" to "a voltage greater than or equal to 40 kV" to capture a larger aggregate of resources.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	

No objection to the applicability for PRC-002-5. However the language for PRC-028-1 the scope of what is applicable and what isnt for IBRs needs clarification. Also, the PRC-028 defines IBR which isn't in the NERC Glossary of Terms. It would be preferable to have this term defined before use in the PRC-028 standard.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
No objection to the applicability for PRC-002-5. However the language for PRC-028-1 the scope of what is applicable and what isnt for IBRs needs clarification. Also, the PRC-028 defines IBR which isn't in the NERC Glossary of Terms. It would be preferable to have this term defined before use in the PRC-028 standard.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	No
Document Name	
Comment	
NRG agrees with NAGF's comments concerning applicability language. The language proposed for applicability to PRC-002 is acceptable but not with regards to language proposed for PRC-028. NRG supports NAGF's comments that this needs to"*align with the pending NERC Glossary of Terms GO/GOP definition revisions".*	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	

Comment	
AZPS supports the proposed language contained in the Applicabiity section for PRC-002-5. However, we do not support the proposed language contained in the Applicability section of PRC-028-1 because the phrase “The Elements associated with” is too broad and subjective. AZPS would support the language if that phrase was removed.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
For PRC-002, yes. For PRC-028, no. There is no filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Some engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion rather than requiring every site to install DME.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye Power supports the comments made by ACES: We at ACES appreciate the efforts of the SDT to deal with the nebulous topic that is IBRs. It is certainly a difficult task to create a new Reliability Standard and carefully craft the language thereof. We see no issue with the update to Section 4.2 of PRC-002-5 draft 2 and in fact appreciate the SDT’s conciseness in this area. However, we do have several concerns with Section 4 of PRC-0028-1 draft 2. It is our opinion that taking a blanket approach for TOs with respect to non-BES IBRs creates confusion, is not in line with the latest revisions to the NERC Rules of Procedure, and represents an unreasonable level of compliance scope creep. It is our opinion that requiring the TO to install monitoring equipment on non-BES Elements is contradictory to the scope of the TO in the NERC Rules of Procedure. We believe that the role of the TO should be limited to Facilities as defined in the NERC Glossary of Terms (i.e., BES only). As stated in the Technical Rationale, “It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an IBR generating facility.” As this is an uncommon occurrence, we do not believe that exceeding the scope of the TO’s registration represents any significant reduction in risk to the BES. Therefore, we recommend modifying Section 4 of PRC-028-1 as follows: 4. Applicability:	

4.1 Functional Entities:
4.1.1 Transmission Owner that owns equipment as identified in section 4.2.1.
4.1.2 Generator Owner that owns equipment identified in section 4.2.
4.2 Facilities:
4.2.1 Elements associated with a BES Inverter-Based Resource(s)
4.2.2 Elements associated with a non-BES Inverter-Based Resource(s) that is:
4.2.2.1 Connected to the Bulk Power System, and
4.2.2.2 Meets the criteria for a Category 2 GO facility.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Including non-BES IBRs for PRC-028-1 could present additional financial difficulties that might cause some GOs to consider other options. Due to the expenses of NERC Registry and PRC-028 requirements, non-BES IBR facilities could possibly be shut-down rather than meet the upcoming NERC requirements.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with NAGF comments. NAGF supports the “Applicability, Section 4.2. Facilities” language proposed for PRC-002-5. The NAGF does not support the “Applicability, Section 4.2. Facilities” language proposed for PRC-028-1. The NAGF notes that the language for PRC-028-1 needs to align with the pending NERC Glossary of Terms GO/GOP definition revisions and therefore, recommend that the PRC-028-1 “Applicability, Section 4.2. Facilities” language be revised as follows:

“4.1.1. Transmission Owner that owns equipment as identified in Facilities section

4.1.2. Generator Owner that owns equipment as identified in Facilities section

Facilities: The Elements associated with (1) BES Inverter-Based Resources; (2) – to be defined and align with the pending NERC Glossary of Terms GO/GOP definition revisions."

Additionally, Black Hills Corporation agrees with the following comment from EEI:

IBR & Unit IBR Definitions:

The IBR and IBR Unit definitions should be removed from PRC-002 and PRC-028 because the associated SAR does not provide this SDT with the authority to develop or adopt a definition that is currently unapproved. Moreover, once these definitions are approved and added to the Glossary of Terms there will be no need for inclusion of the definitions within these Reliability Standards.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Tri-State agrees with MRO Comments.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC has signed on to ACES comments:

We at ACES appreciate the efforts of the SDT to deal with the nebulous topic that is IBRs. It is certainly a difficult task to create a new Reliability Standard and carefully craft the language thereof. We see no issue with the update to Section 4.2 of PRC-002-5 draft 2 and in fact appreciate the SDT's conciseness in this area. However, we do have several concerns with Section 4 of PRC-0028-1 draft 2. It is our opinion that taking a blanket approach for TOs with respect to non-BES IBRs creates confusion, is not in line with the latest revisions to the NERC Rules of Procedure, and represents an unreasonable level of compliance scope creep.

It is our opinion that requiring the TO to install monitoring equipment on non-BES Elements is contradictory to the scope of the TO in the NERC Rules of Procedure. We believe that the role of the TO should be limited to Facilities as defined in the NERC Glossary of Terms (i.e., BES only).

As stated in the Technical Rationale, “It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an IBR generating facility.” As this is an uncommon occurrence, we do not believe that exceeding the scope of the TO’s registration represents any significant reduction in risk to the BES. Therefore, we recommend modifying Section 4 of PRC-028-1 as follows:

4. Applicability:

4.1 Functional Entities:

4.1.1 Transmission Owner that owns equipment as identified in section 4.2.1.
4.1.2 Generator Owner that owns equipment identified in section 4.2.

4.2 Facilities:

4.2.1 Elements associated with a BES Inverter-Based Resource(s)

4.2.2 Elements associated with an non-BES Inverter-Based Resource(s) that is:

4.2.2.1 Connected to the Bulk Power System, and
4.2.1.14.2.2.2 Meets the criteria for a Category 2 GO facility.

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

For PRC-002, yes. For PRC-028, no. There is no filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Some engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion rather than requiring every site to install DME.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Including non-BES IBRs for PRC-028-1 could present additional financial difficulties that might cause some GOs to consider other options. Due to the expenses of NERC Registry and PRC-028 requirements, non-BES IBR facilities could possibly be shut-down rather than meet the upcoming NERC requirements. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), the MRO NSRF, and the NAGF for question #1.	
Likes 0	
Dislikes 0	

Response
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	
No, CenterPoint Energy Houston Electric, LLC (CEHE) supports Edison Electric Institute (EEI) comments submitted for question 1.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question. Additionally, PRC-028, Section 4.2 the wording should be modified to define equal to or greater than 20MVA (and/or?) connected to a common point equal to or greater than 60kV. The proposed wording is ambiguous.	
Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company is in agreement with EEI and does not support the language contained in the Applicability section of PRC-028-1 because the phrase “The Elements associated with” is too broad and subjective. To address this concern, we suggest deleting that phrase (see below).	

Facilities: [***The Elements associated with]*** **REMOVE...** (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

In addition, Southern Company recommends the applicability section in PRC-028, should include a clause for filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion (risk-based approach) rather than requiring every site to install DME.

Southern agrees with the Applicability changes proposed in PRC-002-5.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

Southern Indiana Gas & Electric, Company (SIGE) supports Edison Electric Institute (EEI) comments submitted for question 1.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

EEI does not object to the proposed language contained in the Applicability section for PRC-002-5, however, we do not support the language contained in the Applicability section of PRC-028-1 because the phrase “The Elements associated with” is too broad and subjective. To address this concern, we suggest deleting that phrase (see below).

Facilities: **The Elements associated with** (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	

Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	

Comment

:PG&E agrees with the changes to PRC-002 which explicitly exclude IBRs from the standard. PG&E does not agree with the changes to PRC-028-1 Applicability, Section 4.2 Facilities. PG&E concurs with the EEI comments which indicated they do not agree with the proposed language contained in the Applicability section of PRC-028-1 for the following reasons:

1 - Given the voltage identified with Non-BES IBRs, DPs should be added to the Functional Entities section.

2 - Applying the phrase all Elements to non-BES IBR units is too broad and subjective for use with these resources.

3 - Clarity is needed as to what is and is not in scope for IBR resources.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Additionally, PRC-028, Section 4.2 the wording should be modified to define equal to or greater than 20MVA (and/or?) connected to a common point equal to or greater than 60kV. The proposed wording is ambiguous.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	No
Document Name	
Comment	

The threshold of 20MW seems low and would create additional burden on the utilities to have to install all the equipment to monitor what is being required.

Likes 0	
Dislikes 0	
Response	

Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk

Answer	No
Document Name	
Comment	

Minnesota Power supports MRO NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	
Response	

Megan Melham - Decatur Energy Center LLC - 5

Answer	No
Document Name	
Comment	

Capital Power supports the comments submitted by NAGF.

Capital Power does not agree with the modification in "Applicability, Section 4.2. Facilities" for PRC-028-1. The language for PRC-028-1 needs to align with the pending NERC Glossary of Terms GO/GOP definition revisions. Capital Power recommends that the PRC-028-1 "Applicability, Section 4.2. Facilities" language be revised as follows:
4.1.1. Transmission Owner that owns equipment as identified in Facilities section
4.1.2. Generator Owner that owns equipment as identified in Facilities section
Facilities: The Elements associated with (1) BES Inverter-Based Resources; (2) to be defined and align with the pending NERC Glossary of Terms GO/GOP definition revisions.

Capital Power agrees with the modification in "Applicability, Section 4.2. Facilities" for PRC-002-5.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

For PRC-002, yes. For PRC-028, no. There is no filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Some engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion rather than requiring every site to install DME.

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	No
Document Name	
Comment	

We at ACES appreciate the efforts of the SDT to deal with the nebulous topic that is IBRs. It is certainly a difficult task to create a new Reliability Standard and carefully craft the language thereof. We see no issue with the update to Section 4.2 of PRC-002-5 draft 2 and in fact appreciate the SDT's conciseness in this area. However, we do have several concerns with Section 4 of PRC-0028-1 draft 2. It is our opinion that taking a blanket approach for TOs with respect to non-BES IBRs creates confusion, is not in line with the latest revisions to the NERC Rules of Procedure, and represents an unreasonable level of compliance scope creep.

It is our opinion that requiring the TO to install monitoring equipment on non-BES Elements is contradictory to the scope of the TO in the NERC Rules of Procedure. We believe that the role of the TO should be limited to Facilities as defined in the NERC Glossary of Terms (i.e., BES only).

As stated in the Technical Rationale, "It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an IBR generating facility." As this is an uncommon occurrence, we do not believe that exceeding the scope of the TO's registration represents any significant reduction in risk to the BES. Therefore, we recommend modifying Section 4 of PRC-028-1 as follows:

4. Applicability:

4.1 Functional Entities:

4.1.1 Transmission Owner that owns equipment as identified in section 4.2.1.

4.1.2 Either of the following Generator Owner types that owns equipment identified in section 4.2:.

4.1.1.1 Category 1 Generator Owner

4.1.1.1 Category 2 Generator Owner

4.2 Facilities: Elements associated with either of the following facility types:

4.2.1 Elements associated with a BES Inverter-Based Resource(s) connected to the Bulk Electric System

4.2.2 Elements associated with an non-BES Inverter-Based Resource(s) that is:

4.2.2.1 cConnected to the Bulk Power System, that and

4.2.2.2 mMeets the criteria for a Category 2 GO facility.

Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

For PRC-002, yes. For PRC-028, no. There is no filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Some engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion rather than requiring every site to install DME.

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	

The ISO/RTO Council (IRC) Standards Review Committee (SRC) asks the SDT to clarify Figure 1 in the PRC-002-5 Technical Rationale (page 2) to ensure adequate data is available to facilitate analysis of Bulk Electric System (BES) Disturbances. Currently, the title for Figure 1: “Example to Clarify Applicability of PRC-002 Versus PRC-028” uses the word “versus” which seems to denote only one or the other standard is applicable. Therefore, the SRC asks the SDT to clarify Figure 1 and the supporting text to clearly indicate that data relative to breaker #3 is subject to both PRC-002-5 and PRC-

028-1. This will serve to illustrate that Facilities that are part of protection schemes that overlap with Facilities covered by PRC-028-1 are not automatically excluded from PRC-002 applicability.	
Likes 0	
Dislikes 0	
Response	
Patricia Ireland - DTE Energy - 4	
Answer	No
Document Name	
Comment	
For PRC-028 section 4.2: 20 MVA is too low of a diminimus. With this facility definition, implementation of this standard will be unduly burdensome	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not object to the proposed language contained in the Applicability section for PRC-002-5, however, we do not support the language contained in the Applicability section of PRC-028-1 because the phrase “The Elements associated with” is too broad and subjective. To address this concern, we suggest deleting that phrase (see below). **Facilities:** (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 5,6	

Answer	No
Document Name	

Comment

The Applicability section would benefit from simplification and alignment with the other IBR-focused standards in development. As currently drafted, PRC-028-1, PRC-029-1, and PRC-030-1 all use different language to describe the same applicable Facilities.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF supports the "Applicability, Section 4.2. Facilities" language proposed for PRC-002-5. The NAGF does not support the "Applicability, Section 4.2. Facilities" language proposed for PRC-028-1. The NAGF notes that the language for PRC-028-1 needs to align with the pending NERC Glossary of Terms GO/GOP definition revisions and therefore, recommend that the PRC-028-1 "Applicability, Section 4.2. Facilities" language be revised as follows:

"4.1.1. Transmission Owner that owns equipment as identified in Facilities section

4.1.2. Generator Owner that owns equipment as identified in Facilities section

***Facilities:** The Elements associated with (1) BES Inverter-Based Resources; (2) – to be defined and align with the pending NERC Glossary of Terms GO/GOP definition revisions."*

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

No objection to the applicability for PRC-002-5. However, in the language for PRC-028-1 the scope of what is applicable and what isn't for IBRs needs clarification. Also, the PRC-028 defines IBR which isn't in the NERC Glossary of Terms. It would be preferable to have this term defined before use in the PRC-028 standard.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5,6

Answer	No
Document Name	

Comment

The Applicability section would benefit from simplification and alignment with the other IBR-focused standards in development. As currently drafted, PRC-028-1, PRC-029-1, and PRC-030-1 all use different language to describe the same applicable Facilities.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

If there is a small IBR resource (<20MVA) that is connected on a collector system that connects into a >=60kV system, it wouldn’t fall under PRC-028. If a few years later a separate entity connects another IBR-based resource on that same system that brings the aggregate MVA above the threshold of 20MVA, how would the original GO know that they now fall under the PRC-028 standard?

Similarly, if there are multiple separate entities sharing a common point of interconnect on a >=60kV system and they each contribute to a >=20MVA aggregate, is it the expectation that each of these GOs be familiar enough with the surrounding system and generation resources to know that they fall under the requirements of this new standard?

Specific to PRC-028-1 R2.1., if fault recording data is measured on the high-side of the main power transformer, current injected by the inverters may be swamped out by ground current from the main power transformer for ground faults on the transmission system if the main power transformer is configured to be a ground source for transmission faults. This has been observed at IBR plants connected to Idaho Power's system. If the goal is to record plant-level current injected by the inverters, we recommend changing R2.1 to obtain FR data at the low-side of the main power transformer.

These are all challenges that could develop, if not addressed.

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

While AEP agrees with the modification of the Applicability sections, we believe it would provide consistency across standards if the BPS registration criteria was referenced for the applicable IBR entities. For example, in the most recent draft of PRC-029, they simply point to the BPS registration criteria. Might that be considered here also? If all standards are to meet the FERC 901 order, this might be an idea to consider.

Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Reclamation agrees with the PRC-002-5 but PRC-028 does not apply to Reclamation.

Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	Yes
Document Name	
Comment	
YES	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	

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	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
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 RSC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends revising Section 4.2 Facilities in proposed PRC-028-1 to clarify that both Elements at either BES Inverter-Based Resources or non-BES Inverter-Based resources as described are not required, but the scenario of either or both could exist. Texas RE proposes the following verbiage:

4.2. Facilities

4.2.1 The Elements associated with BES Inverter-Based Resources

4.2.2 The Elements associated with Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
WECC has no comments on PRC-002-5. For PRC-028-1, the use of the term “Element” to describe Facilities included per “Applicability, Section 4.2 Facilities” may confuse industry as the definition of Facility references “single” BES Element. Consider dropping the phrase “The Elements associated with” as the Requirements dictate which equipment is in scope (and the “Functional Entities” section mention equipment. Would consider saying for 4.1.1 and 4.1.2 “..that owns Facilities as identified in section 4.2.” to provide more clarification.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
NERC has not provided any cost benefit analysis to suggest PRC-028 will provide a reliability benefit commensurate with the significant costs expected to be paid by applicable Generator Owners.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Cannot determine cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF notes that requiring data monitoring equipment at all IBR facilities is unnecessary and an excessive cost burden for existing IBR facility owners to bear which may lead to unintended adverse impacts to reliability. *The NAGF requests additional clarification regarding the language "if capable of recording" used in Requirement 1.3 to better understand the cost impacts of the proposed PRC-028-1.*	
Likes 0	

Dislikes 0	

Response

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2

Answer	No
Document Name	

Comment

SPP has a concern about the applicability of this question.

In reference to PRC-002, the drafting team has not provided any analytical data to show industry the potential of any cost to implement this standard. We understand that there were some non-substantive changes in the standard that would suggest no major cost. From our perspective, the question can't be answered about cost effectiveness when there is no data to review.

Additionally, the implementation plan for PRC-028 states that the standard will need various phase-in dates for the standard; however, there is no data to show what the cost will be to implement changes in reference to addressing industry's compliance need. Some type of cost analysis report should be produced to help industry measure concerns like man hours as well as installation of equipment from a compliance perspective.

SPP recommends that the drafting team provide information on cost-effectiveness (if equipment installation is required and/or man hours required to implement) to help them get a better understanding of the implementation cost and the opportunity to provide quality feedback to NERC in reference to cost effectiveness.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 5,6

Answer	No
Document Name	

Comment

NERC has not provided any cost benefit analysis to suggest PRC-028 will provide a reliability benefit commensurate with the significant costs expected to be paid by applicable Generator Owners.

Likes 0	
Dislikes 0	

Response

Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano

Answer	No
Document Name	
Comment	

The SDT has not provided a cost estimate nor tangible reliability indices improvements said modifications are projected to provide. No standard should be allowed if a cost/benefit analysis is not provided by the SDT. SDT frequently asks this question but never provides a cost/benefit justification. SDTs and others, usually simply says there is a reliability gap, or a risk, but does not provide estimated, tangible, reliability indices improvement numbers or a cost estimate to fill the alleged gap or risk.

Likes 0	
Dislikes 0	
Response	

Patricia Ireland - DTE Energy - 4

Answer	No
Document Name	
Comment	

Meeting the PRC-028 monitoring requirements will involve the installation of expensive monitoring equipment at locations with minimal impact on the BES

Likes 0	
Dislikes 0	
Response	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	
Comment	

Requiring DME equipment at all IBR facilities will be excessively costly compared to the value having the equipment. It is hard to believe that every single IBR site needs to have this equipment installed.

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	No
Document Name	
Comment	

It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement.

As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we strongly disagree with making this new standard inclusive of all applicable IBR facilities **regardless of risk to the BES**.

In the opinion of ACES, a blanket approach requiring every applicable IBR facility to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which IBR facilities would provide the most benefit to the BES, before selectively adding such capabilities.

In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach as is done in PRC-002-5.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	

NO. The SDT has not provided a cost estimate nor tangible reliability indices improvements said modifications are projected to provide. No standard should be allowed if a cost/benefit analysis is not provided by the SDT. SDT frequently asks this question but never provides a cost/benefit justification. SDTs and others, usually simply says there is a reliability gap, or a risk, but does not provide estimated, tangible, reliability indices improvement numbers or a cost estimate to fill the alleged gap or risk.

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

Requiring DME equipment at all IBR facilities will be excessively costly compared to the value having the equipment. It is hard to believe that every single IBR site needs to have this equipment installed.	
Likes 0	
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the comments submitted by NAGF. Capital Power notes that requiring data monitoring equipment at all IBR facilities is unnecessary and an excessive cost burden for existing IBR facility owners to bear which may lead to unintended adverse impacts to reliability. PRC-028-1 creates a more restrictive requirement on IBR facilities for data monitoring than for synchronous generation facilities. The requirement for data monitoring equipment should align between the two types of generating resources by requiring the TOP or applicable RE to indicate that monitoring equipment is necessary for the IBR facility. Additional clarification regarding the language “if capable of recording” used in Requirement 1.3 is requested to better understand the cost impacts of the proposed PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
The threshold of 20MW seems low and would create additional burden on the utilities to have to install all the equipment to monitor what is being required.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
PRC-028 should follow PRC-002 with criteria to filter the BES Elements required to provide SER and FR data, as well as DDR data. The cost of all IBR facilities providing this data seems excessive without some analysis first of which sites will provide the most benefit. Capturing all fault codes and all fault alarms under requirements R1.2 and R1.3 will also not provide much benefit vs. the cost.	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
The modifications include existing IBRs now and require monitoring specific elements that may be costly to implement especially for the units that are at a distance greater then or equal to 90% of the longest collector feeder. The proposed requirements for IBRs that will be installed are reasonable as new sites can be built to include that monitoring.	
Likes 0	
Dislikes 0	
Response	

Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company does not agree that the modifications are cost effective. For PRC-028-1, requiring DME equipment at all IBR facilities does not comport with the NERC risk-based approach. To incorporate an informed, risk-based approach to reliability, Southern would propose limiting the applicability through an engineering assessment to evaluate critical sites based on location, vendor susceptibility to trouble, or some other valid criterion. Southern agrees that the modifications made in PRC-002-5 are cost effective.	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
The granularity of the distribution feeder level is questioned as to the need for such information and how it will be used. In order to store the data, new applications are needed which are not economical.	
Likes 0	
Dislikes 0	
Response	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	No
Document Name	
Comment	
TransAlta supports the comments provided by AEP.	
Likes 0	
Dislikes 0	

Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
The modifications proposed in new Standard PRC-028-1 are not cost effective in preventing undesirable IBR responses during Bulk Electric System faults.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the MRO NSRF and the NAGF for question #2.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
The modifications made in this PRC-028-1 draft are an improvement in cost expenditures from the initial version. However, the implementation costs for PRC-028-1 are still appreciably higher than PRC-002. With the additional data requirements and higher sampling rates, the costs are higher per facility for PRC-028 than PRC-002. With DME required to be implemented at all BES IBR facilities and many non-BES IBR facilities, the overall costs of PRC-028 exceeds PRC-002.	

Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
The level of data recording required and the amount of data that is to be collected is significantly greater than PRC-002. Also, requiring all applicable Facilities to have a DDR seems excessive. For PRC-002, the threshold for DDR is governed by a notification by the RC of applicable BES Elements however there is no comparable Requirement in PRC-028 resulting in all IBR generation being obligated to provide DDR data. There is a significant cost associated with the installation and maintenance of a DDR and expecting an IBR to have this level of recording when they do not meet the BES definition may be overreaching. Could this be better addressed by TOs having DDRs that could capture more information from multiple generation facilities during an event?	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	

Comment	
Requiring DME equipment at all IBR facilities will be excessively costly compared to the value having the equipment. It is hard to believe that every single IBR site needs to have this equipment installed.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments: It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement. As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we s**trongly disagree** with making this new standard inclusive of all applicable IBR facilities r**egardless of risk to the BES**. In the opinion of ACES, a blanket approach requiring every applicable IBR facility to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which IBR facilities would provide the most benefit to the BES, before selectively adding such capabilities. In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach as is done in PRC-002-5.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State can not comment on cost effectiveness at this time.	
Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	

The modifications made in this PRC-028-1 draft are an improvement in cost expenditures from the initial version. However, the implementation costs for PRC-028-1 are still appreciably higher than PRC-002. With the additional data requirements and higher sampling rates, the costs are higher per facility for PRC-028 than PRC-002. With DME required to be implemented at all BES IBR facilities and many non-BES IBR facilities, the overall costs of PRC-028 exceeds PRC-002.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	
Comment	

Buckeye Power supports the comments made by ACES:

It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have litle to no cost to implement.
As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we strongly disagree with making this new standard inclusive of all applicable IBR facilities regardless of risk to the BES.
In the opinion of ACES, a blanket approach requiring every applicable IBR facility to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which IBR facilities would provide the most benefit to the BES, before selectively adding such capabilities.
In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach as is done in PRC-002-5.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

Requiring DME equipment at all IBR facilities will be excessively costly compared to the value having the equipment. It is hard to believe that every single IBR site needs to have this equipment installed.

Likes 0	
Dislikes 0	

Response

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	No
Document Name	

Comment

Yes for new IBR facilities. For existing IBR facilities, the location requirements are reasonable; however, the required sample rates and data retention requirements may require additional investment in the collector substation.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

For the reasons expressed below, AEP is concerned by the cost versus perceived reliability benefit of the new Standard PRC-028-1.

AEP does not consider the inclusion of “at least one IBR Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% of the longest collector feeder” in PRC-028 1.2 and 1.3 as cost effective. AEP questions the reliability benefit of the data these BES Elements will provide when considering the proposed requirements of PRC-029 to a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances and the proposed requirements of PRC-030, Unexpected Inverter-Based Resource Event Mitigation. Requirements proposed in PRC-030 clearly make the GO responsible for the performance of the Invertor-Based Resources and IBR units it owns. The proposed obligation to collect and provide FR and SER data beyond the MPT bus(es) in PRC-028 is unwarranted.

PRC-028 does not currently limit the applicability of required data, while PRC-002 provides criteria which limits the BES Elements that are required to have dynamic disturbance recording data.

AEP does not believe capturing all fault codes and fault alarms listed in R1.2 and R1.3 under this standard would be beneficial to the Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC as there are several OEMs with thousands of differing fault codes and fault alarms. AEP is concerned with the ability of these entities to understand or utilize the data in an timely manner. For some entities, this data would be more akin to SCADA quality data and not delivered with the timing nor accuracy of typical SER data. In addition, under PRC-030, we are asking the GO to resolve those issues. AEP recommends the SDT for PRC-028, PRC-029 and PRC-030 review each proposed standard obligation to ensure there is an integrated plan across these standards to achieve the goal of correcting the past performance of Invertor-Based Resources and IBR units. Having a coherent strategy document that explains how these three standards complement each other (and not be duplicative) would be beneficial.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	No
Document Name	
Comment	
NRG supports NAGFs comments concerning excessive cost burden for IBR facility owners.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Cannot determine cost effectiveness	
Likes 0	
Dislikes 0	
Response	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	No

Document Name	
Comment	

No, simply from a value-add perspective. The standard requires IBR owners to have a robust compliance program implemented as well as event data collection process in place. However, for example, Requirement R1.2 only requires fault codes, fault alarms, mode status change, etc., from a single IBR Unit far down the feeder. This is common practice for this information to be stored on the IBR Unit inverter or logging device.

This will not help any event analysis process as it will not paint an adequate picture of the IBR facility's abnormal performance, if analyzed. At a minimum, fault codes should be available from every single IBR Unit within the facility. Lack of comprehensive data has significantly affected the ERO Enterprise's ability to conduct event analysis at many facilities over the past 7 years, as reported in numerous disturbance reports. The proposed standard would lead to inadequate data available at the inverter-level to do any useful event analysis and model validation, possibly leading to ongoing inconclusive root cause analyses. This would not be cost effective for industry.

Likes 0	
Dislikes 0	
Response	

Rob Robertson - Leeward Renewable Energy - 5

Answer	No
Document Name	LRE PRC-028 April 2024 comments April 11 2024.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	Yes
Document Name	
Comment	

"See comments submitted by the Edison Electric Institute"

Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
SRP believes that while implementation of these changes may be costly, they provide high value from operation, integration, and monitoring perspective.	
Likes 0	
Dislikes 0	
Response	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation agrees with the PRC-002-5 cost but inverter base does not apply to Reclamation.	
Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
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	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
No comment.	

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: 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 does not have any input on this question.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

No comment

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

CEHE abstains from responding.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	

Comment
Black Hills Corporation will not comment on cost effectiveness.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	

Comment
Cannot determine cost effectiveness.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	

Comment
Duke Energy's focus is to assure the effective and efficient reduction of risks to the reliability and security of the grid and will not provide comments on the cost effectiveness of the proposed changes.

Likes 0	
Dislikes 0	

Response

3. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is unable to support the current Implementation Plan driven by our concerns with the scope and requirements of the current draft of PRC-028.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Implementation Plan Says: R1-7: Current imp plan is 50% in 3 calendar years after effective date, 100% by 1/1/2030 R8: max 9 months after effective date R9: no later than 1/1/2029 The phased in implementation plan needs to be given in a time frame after the effective date for the standard. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all IBR facilities. PRC-028, as written, will require much more DME than did PRC-002, and the implementation plan needs to recognize this difference and provide adequate time to accomplish.	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	

Reclamation supports an 18-month implementation time frame.

Likes 0	
Dislikes 0	
Response	

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Buckeye Power supports the comments made by ACES:

As writen, PRC-028-1 is applicable to both BES and non-BES IBRs; consequently, we recommend updating the Implementation Plan to use the term “IBR facility(ies)” in lieu of the term defined term “Facility(ies)”.
From the perspective of ACES, the special stipulations surrounding commercial operation are overly complex and unnecessary. For example, assume PRC-028-1 is approved by FERC and becomes effective 10/1/2024. Using the provided example, the end of the first calendar year that is 12 months following the effective date of the standard would be 12/31/2025. Thus any facilities entering commercial operation prior to 10/1/2025 would have until 12/31/2025 to be compliant while any facilities entering commercial operation on or after 10/1/2025 must be compliant immediately. We do not believe that a delay of only 1 day should move the compliance deadline forward by 3 calendar months.
We recommend removing these special stipulations and instead address this specific case using a strategy akin to that used for existing facilities. We suggest the following language:
“For facilities entering commercial operation a□er the effective date: Entities shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of PRC-028-1.”

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Although the PRC-028 Implementation Plan mirrors PRC-002-2 Implementation Plan, PRC-028 requires all BES IBRs and many non-BES IBRs to have DME installed. If the GO has a large IBR fleet, numerous DME installations would be required with a demanding project schedule. With the large amount of DME required to be installed per PRC-028, OEMs might not be able to provide GOs with a timely supply of DME equipment.

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments:

As written, PRC-028-1 is applicable to both BES and non-BES IBRs; consequently, we recommend updating the Implementation Plan to use the term “IBR facility(ies)” in lieu of the term defined term “Facility(ies)”.

From the perspective of ACES, the special stipulations surrounding commercial operation are overly complex and unnecessary. For example, assume PRC-028-1 is approved by FERC and becomes effective 10/1/2024. Using the provided example, the end of the first calendar year that is 12 months following the effective date of the standard would be 12/31/2025. Thus any facilities entering commercial operation prior to 10/1/2025 would have unϴl 12/31/2025 to be compliant while any facilities entering commercial operation on or after 10/1/2025 must be compliant immediately. We do not believe that a delay of only 1 day should move the compliance deadline forward by 3 calendar months.

We recommend removing these special stipulations and instead address this specific case using a strategy akin to that used for existing facilities. We suggest the following language:

“For facilities entering commercial operation after the effective date:

Entities shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of PRC-028-1.”

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

Implementation Plan Says:

R1-7: Current imp plan is 50% in 3 calendar years after effective date, 100% by 1/1/2030

R8: max 9 months after effective date

R9: no later than 1/1/2029

The phased in implementation plan needs to be given in a time frame after the effective date for the standard. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all IBR facilities. PRC-028, as written, will require much more DME than did PRC-002, and the implementation plan needs to recognize this difference and provide adequate time to accomplish.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Although the PRC-028 Implementation Plan mirrors PRC-002-2 Implementation Plan, PRC-028 requires all BES IBRs and many non-BES IBRs to have DME installed. If the GO has a large IBR fleet, numerous DME installations would be required with a demanding project schedule. With the large amount of DME required to be installed per PRC-028, OEMs might not be able to provide GOs with a timely supply of DME equipment.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	No
Document Name	

Comment

TransAlta recommends removing the stipulations surrounding commercial operation. There are associated project execution risks with making design changes later in a project. TransAlta would prefer to have the flexibility to install and/or configure monitoring equipment after commercial operation. Thus, TransAlta recommends updating the implementation plan to specify compliance with Requirements R1 through R7 at 50% of plants/Facilities within 3 calendar years and 100% within 6 calendar years for all plants/Facilities regardless of commercial operation date.

Likes 0	
Dislikes 0	

Response

Kenisha Webber - Entergy - NA - Not Applicable - SERC

Answer	No
Document Name	

Comment

Propose three (3) calendar years instead of one (1) year for budgeting and planning purposes.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

The Plan is too agressive. Dominion Energy recommends an additional 12-24 months to accomodate all of the non-BES IBRs that need to now be included.

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	

The PRC-028-1 standard as written, requires 50% completion within (3) calendar years and 100% completion of R1-R7 by 1/1/2030, R9 by 1/1/2029 and R8 a maximum of 9 months after the effective date. The phased-in implementation plan needs to be given in a timeframe after the effective date for the standards. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all applicable IBR facilities. PRC-028, as written, will require much more DME than PRC-002 did, and the implementation plan needs to recognize this difference and provide adequate time to accomplish. Traditional language for implementation plans in other Standards have provided a certain period after implementation instead of a fixed date (e.g. within 6 calendar years of the effective date…).

Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	
Comment	

NIPSCO is not able to support the current implementation plan until concerns with the requirements of PRC-028 are addressed.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	
Comment	

See response to questions 4 and 5

Likes 0	
Dislikes 0	
Response	

Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Implementation Plan Says: R1-7: Current imp plan is 50% in 3 calendar years after effective date, 100% by 1/1/2030 R8: max 9 months after effective date R9: no later than 1/1/2029 The phased in implementation plan needs to be given in a time frame after the effective date for the standard. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all IBR facilities. PRC-028, as written, will require much more DME than did PRC-002, and the implementation plan needs to recognize this difference and provide adequate time to accomplish.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
No. Entities more need time to budget for projects and to coordinate modifications.	

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	No
Document Name	

Comment

As written, PRC-028-1 is applicable to both BES and non-BES IBRs; consequently, we recommend updating the Implementation Plan to use the term "IBR facility(ies)" in lieu of the term defined term "Facility(ies)".

From the perspective of ACES, the special stipulations surrounding commercial operation are overly complex and unnecessary. For example, assume PRC-028-1 is approved by FERC and becomes effective 10/1/2024. Using the provided example, the end of the first calendar year that is 12 months following the effective date of the standard would be 12/31/2025. Thus any facilities entering commercial operation prior to 10/1/2025 would have until 12/31/2025 to be compliant while any facilities entering commercial operation on or after 10/1/2025 must be compliant immediately. We do not believe that a delay of only 1 day should move the compliance deadline forward by 3 calendar months.

We recommend removing these special stipulations and instead address this specific case using a strategy akin to that used for existing facilities. We suggest the following language:

"For facilities entering commercial operation after the effective date:
Entities shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of PRC-028-1."

Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

Implementation Plan Says:

R1-7: Current imp plan is 50% in 3 calendar years after effective date, 100% by 1/1/2030

R8: max 9 months after effective date

R9: no later than 1/1/2029

The phased in implementation plan needs to be given in a time frame after the effective date for the standard. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all IBR facilities. PRC-028, as written, will require much more DME than did PRC-002, and the implementation plan needs to recognize this difference and provide adequate time to accomplish.

Likes 0	
Dislikes 0	

Response

Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano

Answer	No
Document Name	

Comment

Entities need more time to budget for projects and to coordinate modifications.

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

Robert Follini - Avista - Avista Corporation - 3

Answer	Yes
Document Name	

Comment

Implementation plan seems reasonable. Changes to PRC-002 are clarifying in nature, for the removal of IBRs. PRC-028 would be a new PRC with a 3 year implementation.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Implementation plan seems reasonable. Changes to PRC-002 are clarifying in nature, for the removal of IBRs. PRC-028 would be a new PRC with a 3 year implementation.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
While FirstEnergy supports the Implementation Plan, we offer our comments. See our response to Q4.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
We recognize that there is a cost but the benefits to relaibility are worthwhile.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Six years would be a sufficient amount of time to plan and budget for the procurement and installation of the DDR equipment barring any supply chain risk complications or any other delays. USV recognizes the FERC directive mandating completion by 1/1/2030, however, due to many of the IBR sites having strict language when dealing with manufacturers warranty and having to rely on third parties, it may result in additional complications that could delay the installation and setting up of this highly specialized equipment.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the NAGF for question #3.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
EEI supports proposed implementation plan as developed for PRC-002 and PRC-028.	

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: 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

{C}PG&E supports the proposed implementation plan as developed for PRC-002 and PRC-028.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	Yes
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports proposed implementation plan as developed for PRC-002 and PRC-028.	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Implementation plan seems reasonable. Changes to PRC-002 are clarifying in nature, for the removal of IBRs. PRC-028 would be a new PRC with a 3 year implementation.	
Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
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	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

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

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
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 RSC	
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	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Patricia Ireland - DTE Energy - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
Tri-State agrees with MRO Comments.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with introduction of Requirement R9 in PRC-028-1 requiring Entities of an applicable facility that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance to develop, maintain, and implement a Corrective Action Plan?

Rhonda Jones - Invenergy LLC - 5,6

Answer	No
Document Name	

Comment

Invenergy **suggests the below language** for R9:

R9. Each Generator Owner and Transmission Owner with a documented equipment limitation that would prevent an applicable IBR that is in commercial operation prior to the effective date of this standard from installing disturbance monitoring equipment in accordance with Requirements R1 through R7 shall communicate each equipment limitation to the Regional Entity.

9.1. Each Generator Owner and Transmission Owner shall include in its documentation:

- 9.1.1. Identifying information of the applicable Element and cause of the limitation
- 9.1.2. Which aspect(s) of disturbance monitoring the Element would be unable to meet

9.2. Each Generator Owner and Transmission with a previously communicated equipment limitation that repairs or replaces the equipment causing the limitation shall document and communicate such equipment change to the Regional Entity within 30 days of the equipment change.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF does not support the proposed Requirement R9 due to the potential cost issues for existing IBR facilities as well as the potential reliability impacts due to existing IBR facilities ceasing operation due to economics.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 5,6

Answer	No
Document Name	
Comment	

Invenergy suggests the below language for R9:

R9. Each Generator Owner and Transmission Owner with a documented equipment limitation that would prevent an applicable IBR that is in commercial operation prior to the effective date of this standard from installing disturbance monitoring equipment in accordance with Requirements R1 through R7 shall communicate each equipment limitation to the Regional Entity.

9.1. Each Generator Owner and Transmission Owner shall include in its documentation:

9.1.1. Identifying information of the applicable Element and cause of the limitation

9.1.2. Which aspect(s) of disturbance monitoring the Element would be unable to meet

9.2. Each Generator Owner and Transmission with a previously communicated equipment limitation that repairs or replaces the equipment causing the limitation shall document and communicate such equipment change to the Regional Entity within 30 days of the equipment change.

Likes 0	
Dislikes 0	
Response	

Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano

Answer	No
Document Name	
Comment	

If the allegation that existing IBR's are causing issues then the requirements should be the same.

Likes 0	
Dislikes 0	
Response	

Patricia Ireland - DTE Energy - 4

Answer	No
Document Name	
Comment	

The idea of allowing a corrective action plan for compliance challenges at existing operations is a good one however the circumstance that would allow for use of the CAP is poorly defined.   What exactly is "not able to install" ? Does that mean within reason? cost effectively?   Not able to install regardless of time or money is a very high bar and essentially unhelpful.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The SRC is concerned that the requirement as written may be overly broad. To address this, examples of legitimate reasons that an entity may be unable to “install disturbance monitoring equipment” should be provided in the Technical Rationale.

Alternatively, this concern could be addressed by revising the standard to require all installations to be completed within the parameters of the Implementation Plan for PRC-028.

Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

Requiring comprehensive DME for SER, FR, and DDR at all "old" facilities is unnecessary.   The investigations performed into past grid disturbances have documented the trouble that legacy facilities have been experiencing.   Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability.

R2.3 and R3.3 and their subparts are unnecessary as these devices have not been identified as causing any problems that suggest they need to be monitored.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
No. If the allegation that existing IBR's are causing issues then the requirements should be the same.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Requiring comprehensive DME for SER, FR, and DDR at all "old" facilities is unnecessary. The investigations performed into past grid disturbances have documented the trouble that legacy facilities have been experiencing. Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability. R2.3 and R3.3 and their subparts are unnecessary as these devices have not been identified as causing any problems that suggest they need to be monitored.	
Likes 0	
Dislikes 0	
Response	

Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the comments submitted by NAGF. Capital Power does not support the proposed Requirement R9 due to the potential cost issues for existing IBR facilities. This can be a costly endeavor if equipment was recently replaced as per planned life cycle replacement strategies. There is also the potential reliability impacts due to existing IBR facilities ceasing operation due to economics.	

Likes 0	
Dislikes 0	
Response	
Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	
Comment	
PG&E does not agree with the language proposed. PG&E agrees with the following EEI comments: 1 - Given the voltage level identified in the Applicability section of PRC-028, DPs will likely own applicable equipment that will be impacted. For this reason, we suggest that DPs be added to R9. 2 - The use of "applicable facility" in R9 should be removed because this term has no defined meaning. To resolve this issue, we suggest replacing "of an applicable facility" with "that own equipment as identified in "Section 4.2 (Facilities)". 3 - Disturbance Monitoring Equipment is a NERC defined term and should be capitalized to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	

Answer	No
Document Name	

Comment

Conceptually, no, WECC believes there should not be a compliance loophole built into a Reliability Standard. General considerations mention three (3) calendar years to accommodate normal outage schedules.   As written the entity may only have to outage one (1) IBR unit per collector feeder (and in some cases maybe only (1) IBR Unit for the entire Inverter-Based Resource), to install equipment in Parts 1.2/2.2. (as an example as it is not clear where that data is being recorded). Granted, SER/FR on circuit breakers, if not already installed at Part 1.1 locations require a complete outage but is it not already industry standard to have that capability on breakers in that voltage class? Waiting until 2029 to create a CAP per the Implementation Plan does not support reliable operations (and at least two "normal outage schedule" periods will have passed since the official start of this Project to accommodate the SER/FR additions if not present.) Part 9.2 allows too broad of a scope to be considered reliable with no support (what is "beyond the control" and who defines that?). Submitting the CAP to the Regional Entity with a request to extend time provided for compliance does not support reliability. The Regional Entity does not necessarily have the authority to grant extensions for compliance. Timelines for compliance are dictated by Implementation Plans or the Requirement language itself. There are no required timelines for the CAP which could equate to a CAP that is never implemented. WECC appreciates the idea of striking a balance between cost and reliability (with compliance impacts) but as written the reliability aspect will suffer to support being compliant.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	No
Document Name	

Comment

Section R3.2 seems to specify that a Schweitzer level sampling rate of 64 samples per cycle needs to be implemented which it does not appear to be within the capabilities of the event recording generated by the turbine controllers. The minimum requirements appear to be the AC and Frequency values at that high of a resolution.

The GE documentation suggest the points and sampling rate of the trip files generated vary. Even if the resolution we need is possible, it may not have the correct setting dependent on the event that is recorded in the trip file. The fastest sampling rate in the GE trending software is at a 10 milli-seconds, which is significantly less than what would be required for 64 samples per 1 hz.

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment	
R9.5 requires Entities submit the CAP to the Regional Entity. Entities will require guidance on the process with input from each Regional Entity. This is an administrative process that could cause undue delay in the CAP process while managing time constraints. It would be more efficient for the Entity to create and maintain its own CAP similar to PRC-026 R3 and R4. The CAP can be made available during periodic audits. There is no demonstration of how "reporting" CAPs to Regional Entities adds to system Reliability. Requiring comprehensive DME for SER, FR, and DDR at all existing facilities is unnecessary. The investigations performed for past grid disturbances have documented the trouble that legacy facilities have been experiencing. Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability. R2.3 and R3.3 and their subparts are not necessary as these devices have not been identified as causing any problems that suggest they need to be monitored. Southern Company agrees with EEI suggested modifications to the text: 1. The use of "applicable facility" in R9 should be removed because this term has no defined meaning. To resolve this issue, it is suggested replacing "of an applicable facility" with "that own equipment as identified in Section 4.2 (Facilities)". 2. Disturbance Monitoring Equipment is a NERC defined term and should be capitalized in order to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), the MRO NSRF, and the NAGF for question #4.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Requiring comprehensive DME for SER, FR, and DDR at all "old" facilities is unnecessary. The investigations performed into past grid disturbances have documented the trouble that legacy facilities have been experiencing. Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability. R2.3 and R3.3 and their subparts are unnecessary as these devices have not been identified as causing any problems that suggest they need to be monitored.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State agrees with MRO Comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	

Comment	
Black Hills Corporation agrees with NAGF comments. The NAGF does not support the proposed Requirement R9 due to the potential cost issues for existing IBR facilities as well as the potential reliability impacts due to existing IBR facilities ceasing operation due to economics. Black Hills Corporation also agrees with this comment from EEI: EEI supports the language proposed in Requirement R9 but offers the following non substantive comments for consideration: 1. The use of "applicable facility" in R9 should be removed because this term has no defined meaning. To resolve this issue, we suggest replacing "of an applicable facility" with "that own equipment as identified in "Section 4.2 (Facilities)". 2. Disturbance Monitoring Equipment is a NERC defined term and should be capitalized in order to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Requiring comprehensive DME for SER, FR, and DDR at all "old" facilities is unnecessary. The investigations performed into past grid disturbances have documented the trouble that legacy facilities have been experiencing. Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability. R2.3 and R3.3 and their subparts are necessary as these devices have not been identified as causing any problems that suggest they need to be monitored	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE asks DT to consider removing R9 and putting it into implementation plan to avoid future administrative burden to retire R9 when all CAPs are complete or consider R9 to mirror PRC-028 R8 or PRC-002 R12 to ease admistrative burden.	

Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	No
Document Name	
Comment	

NRG is in alignment with NAGFs comments regarding Requirement 9 due to potential cost issues and reliability impacts for existing IBR facilites to install this equipment.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy supports and recommends implementation of EEI provided comments.

Additionally, PRC-028-1 R9 that reads: Each Transmission Owner and Generator Owner of an applicable facility as specified in section A.4.2 that is "in commercial operation before the effective date of this standard" that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance shall develop, maintain, and implement a Corrective Action Plan to provide the required capability. For the sake of fully defining compliance expectations, please amend language to define what action, if any, TO/GO entities must take if it is "not in commercial operation before the effective date of this standard".

Likes 0	
Dislikes 0	
Response	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	No
Document Name	
Comment	

No. This appears to be redundant with the development of an effective and reasonable implementation plan for this standard. The proposed implementation plan for 5+ years to get compliant with the standard seems sufficient to install/enable disturbance monitoring equipment. Elevate is not aware of any supply chain or other issues that would cause such long delays (as opposed to high power equipment, controllers, hardware, etc.).	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Wording should be clarified where “applicable facility” is used as this is not a defined term.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the language proposed in Requirement R9 but offers the following non substantive comments for consideration: 1. The use of “applicable facility” in R9 should be removed because this term has no defined meaning. To resolve this issue, we suggest replacing “of an applicable facility” with “that own equipment as identified in “Section 4.2 (Facilities)”. 2. Disturbance Monitoring Equipment is a NERC defined term and should be capitalized in order to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
EEI supports the language proposed in Requirement R9 but offers the following non substantive comments for consideration: {C}1. {C}The use of “applicable facility” in R9 should be removed because this term has no defined meaning. To resolve this issue, we suggest replacing “of an applicable facility” with “that own equipment as identified in “Section 4.2 (Facilities)”. {C}2. {C}Disturbance Monitoring Equipment is a NERC defined term and should be capitalized in order to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes

Document Name	
Comment	

SIGE supports the inclusion of Requirement R9; however, SIGE requests a clarification regarding disturbance monitoring equipment referenced in Requirement R9. Was the Standard Drafting team's use of the phrase "disturbance monitoring equipment" intended to reference the equipment covered by the NERC defined term "Disturbance Monitoring Equipment"? If so, SIGE recommends capitalizing the proposed language to clarify the intent.

Additionally, SIGE recommends two revisions to R9: 1) revise R9 to mirror the language in section 4.2 Functional Entities and 2) align the Applicability section reference with other NERC Standards. Recommended revisions are shown below:

R9. Each Transmission Owner and Generator Owner ***that owns equipment as identified*** in ***Applicability*** section ***4.2*** that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance shall develop, maintain, and implement a Corrective Action Plan to provide the required capability. For each Corrective Action Plan, the Transmission Owner and Generator Owner shall:

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

"See comments submitted by the Edison Electric Institute"

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes. CEHE supports Southern Indiana Gas & Electric, Company comments submitted for question 4.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
If the standard and implementation plan were to pass in its current form, we do not feel that 2030 would be a sufficient amount of time to implement DDR recording at all sites that meet the applicability section of PRC-028. The procurement and installation process is time-consuming due to the limited amount of vendors and having to do additional efforts for supply chain risk, etc.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
SRP agrees with industry that while these changes provide value in evaluating facilities when there are disturbances, however it is also critical to assign responsibility to IBR facilities and their owners to enforce these requirements.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Wording should be clarified where “applicable facility” is used as this is not a defined term.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Wording should be clarified where “applicable facility” is used as this is not a defined term.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 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	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
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 RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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	
Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
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	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
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	
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	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Not applicable to Reclamation.	
Likes 0	
Dislikes 0	
Response	

5. Provide any additional comments for the standard drafting team to consider, if desired.

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	

1) In 4.3.2 of PRC-002-5, we need to clarify this trigger condition "Phase undervoltage or overcurrent". Does "phase undervoltage" refer to phase-phase or phase-to-neutral undervoltage"?

2) Under "Facilities" of 4.1 in PRC-028-1, how was this 60 kV threshold determined?

3) In section 3.1.3.2, section 3.2.3.1 and section 3.3.3.2 of PRC-028-1, we need to clarify this trigger condition "AC phase overvoltage and undervoltage". Does "phase undervoltage" refer to phase-phase or phase-to-neutral undervoltage"?

4) In R8 of PRC-028-1, "Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it." should probably read "Submit a Corrective Action Plan (CAP) and a CAP implementing schedule to the Regional Entity"?

Likes 0	
Dislikes 0	
Response	

Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	
Document Name	
Comment	

It is unclear why NERC is so adamant about not adopting IEEE standards within the NERC standards, and has stated this in multiple forums related to the adoption of IEEE 2800-2022. However, then now proposes to adopt IEEE C37.111 COMTRADE standard within the new PRC-028-1 proposed standard. Inconsistency regarding NERC's approach and opinion in this area leaves industry confused, uncertain, and concerned regarding whether NERC has a clear and effective standards improvement strategy.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	

Comment	
Duke Energy supports and recommends implementation of EEI provided comments.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
Overall wording for the sections mentioned above for PRC-028 should be cleaned up. Terms like IBR should have formal definitions, outside of PRC-028 in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	
Overall wording for the sections mentioned above for PRC-028 should be cleaned up. Terms like IBR should have formal definitions, outside of PRC-028 in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	

BC Hydro appreciates the drafting team efforts and the opportunity to comment.

PRC-028-1 R1 requires an entity to record data “when triggered by ride-through operation”. BC Hydro requests that drafting provides additional clarity on or criteria to determine what would constitute “ride-through operation” as it pertains to an applicable entity’s compliance obligation to identify all events in scope of R1 Part 1.2.

Requirement R3 Footnote 3 on “main power transformer” should use IBR instead of the undefined term “dispersed power producing resources”. BC Hydro suggests that instead of this wording, which is indeed referenced in the inclusion I4 of the BES definition, the new IBR Glossary Term is preferrable.

Requirement R7 requires that all SER, DDR and FR data be provided upon request by an applicable entity. BC Hydro suggests that all data may not be feasible or even required and recommends instead that the provision of the SER, DDR and FR data be done in accordance with a qualified request and within the bounds set by Part 7.1 through Part 7.5 of Requirement R7.

PRC-028-1 Requirement R8 and PRC-002-5 R12 second bullet as written requires that a CAP will need to be implemented within 90 days. The VSL Table and the Technical Rationale provide clarity that it is only the CAP that requires submission within 90 days for the situations where an entity is unable to restore capability within 90 days. BC Hydro recommends that the drafting team revises the PRC-028-1 R8 and PRC-002-5 R12 wording to clarify that the 90-day timeline is only mandated for the CAP submission. Also important to clarify within the language of the Requirement is whether the 90-day timeline is based on business or calendar days.

BC Hydro recommends that the implementation plan for PRC-028-1 be coordinated with the approval of the approval of the IBR and IBR Unit definitions.

Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	

NRG is supportive of NAGFs comments that the Project needs to be closely coordinated with other active NERC IBR related projects to avoid conflicts and duplication of requirements.

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	

Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
This comment applies to PRC-028-1 R5.2. Idaho Power presently requires existing and future IBRs connecting to its transmission system to provide plant-level PMU data. This data is streamed to a central data concentrator in real time, where it is then stored in a central data historian. The message rate has been chosen to be 30 samples per second due to limitations of the communications systems. Moving this existing system to 60 samples per cycle to obtain this data may result in significant re-design and additional costs.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	
AZPS has no additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	

Comment	
AEP has concerns with several of the requirement differences between PRC-002 and PRC-028 such as ten day data retention vs. twenty day data retention, output recording rate of electrical quantities of at least 30 times per second versus 60 times per second, synchronized clock accuracy within +/- 2 milliseconds versus +/- 1 millisecond, etc.. The Technical Rational document is silent on the reason for these differences. These changes are not insignificant, and having differing requirements for synchronous vs IBR technologies, introduces a risk for human performance error. PRC-002 Attachment 1 limits the BES buses required to record SER and FR data. During the recent system disturbance events, were any IBR facility buses required to capture SER and FR data under PRC-002? What is the reliability-driven rationale behind requiring *all* IBR facility buses to capture SER and FR data in PRC-028 as opposed to a targeted set based on an engineering analysis as done for PRC-002? PRC-002 and PRC-028 should both be revised to make it clear that the ability to provide data in CSV format is for DDR or PMU data *only.*	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	

Texas RE has the following additional comments:

- Texas RE suggests removing the terms “machine based” from PRC-002-5 Requirement Part 5.1.1 as simply stating “Synchronous generating resource” is sufficient.
- In PRC-028-1 Standard, Requirement Part 2.1.3 should specify Real and reactive power on a three-phase basis*:*
  - 2.1.3. Real and reactive power on a **three-phase basis.**
- In PRC-028-1 Standard, Requirement Part 2.3.3 should remove ‘Real’ from the requirement and specify the reactive power on a three-phase basis:
  - **2.3.3. Real and Reactive power on three-phase basis.**
- Remove the ending parathesis in Requirement Part 3.2.2.
- Texas RE recommends the SDT consider specifying the trigger settings for ‘overfrequency and underfrequency’ levels to be consistent with the PRC-024 requirements:
  - **3.2.3.2 Overfrequency level at minimum 60.6 Hz and underfrequency level at 59.4 Hz**
- Texas RE recommends the SDT consider including an option for existing registered entities that have IBR units that are incapable of recording data to provide technical justification for the IBR unit’s inability to record based on OEM specifications or based on an independent engineering assessment.

Likes 0	
Dislikes 0	
Response	

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	
Document Name	

Comment

Section 1.2 and 1.3: While IBR settings are important when analyzing events, the various settings and modes may not be recorded by the inverter data recorder. At a minimum 1.3.3 and 1.3.4 should be removed for IBR units that are in commercial operation since they would have not been designed to meet the requirement.

Section 2.1.3: PRC-002 does not require real and reactive power for FR data, the same should apply for PRC-028, Most fault recording equipment does not record power or frequency in FR records, this is a calculated value and is recorded in DDR/Continuous data. Software can be used to calculate power using FR data, power and frequency would not be in the comtrade file.

Section 2.3.3: Same comment as 2.1.3

Section 3.2..2 Existing IBRs may not be able to store 2 second event records at a 64 samples/cycle.

Section 3.2.3.2 Frequency triggers should not be required for FR data. They can be difficult to set and trigger erroneous events which can fill up storage. Frequency triggers should only be required for continuous/DDR recording.

Section 5.2 Not all existing install equipment may be able to meet the 60 samples/second recording rate. Requirement in PRC-002 is 30 samples/second.

Section 7.1 Existing IBRs may not be able to store FR or DDR data for 30 days.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

For R8, it is not clear whether the CAP implementation referenced in the 2nd bullet item must be complete at the end of the 90 days specified in the R8 text. If so, what then is the difference in the first bullet (restoring the capability) and why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit?

In R9.5 does the request to extend the time provided refer to any changes made to an original CAP timeline? (there are no other deadlines for completing any R9 CAP)

In R1.2 and R1.3 remove the unneeded brackets [ ] surrounding “the effective date of this standard”.

CAPS documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment will accomplish the intent of R8 & R9. An audit can check to ensure that all broken equipment was handled properly.

What dictates a “ride-thru” event in R1?   The IBR mode status?

Why is R2.2.1 needed to be the IBR Unit transformer HV side versus the LV side?

Comments on cost:

Based on research for the last ballot on the costs of having this on each feeder at a wind farm. This doesn't include solar IBRS.

In addition, the contributing entity estimates that the cost of installing DFR equipment on the high side of a pad mounted transformer at the base of a wind turbine in the last 10% of an existing wind turbine feeder will be $300-450k or 2-3 times the cost of installing the same equipment in an existing substation. For example, one wind farm has 14 feeders so installing this equipment on every feeder there would cost an estimated $4.2-6.3 million dollars for that one facility.

EIA data shows that there are currently 604 wind farms with a size of 75 MW or greater with a total 975549 MW capacity. Assuming there is a feeder for every 10-20 MW worth of wind turbines and the estimate per installation, the range between $1.463-$2.195 billion dollars just to install these at the end of every feeder and does not include the substation installations that would be required. This estimate is only for feeders at wind turbines and does not include any estimates for solar farms or other IBRs so the total cost.

Likes 0	
Dislikes 0	

Response

Wendy Kalidass - U.S. Bureau of Reclamation - 5

Answer	
Document Name	

Comment

Reclamation does not agree with the modifications to the wording of BES Elements in R6 and R7 in the “Violation Severity Levels” section. ‘Element’ is sufficiently defined in the NERC Glossary of terms and ‘BES Element’ encompasses the required equipment (elements) for Disturbance Monitoring. Reclamation recommends keeping the original wording “for all applicable BES Elements”.

Reclamation concurs that all IBR resources should have and maintain their own separate standards.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	
Document Name	

Comment

Buckeye Power supports the comments made by ACES:

It is unclear as to what constitutes a “ride-through operation” of an IBR Unit in R1.2 and R1.3. Is this intended to be a reference to “no trip zone” identified in PRC-024? If so, as PRC-024 is not currently applicable to non-BES IBRs, how is this identified for those facilities? We believe additional guidance is needed for these requirements.

Likes 0

Dislikes 0

Response

Kimberly Turco - Constellation - 6

Answer

Document Name

Comment

The cost and burden of the proposed PRC-028 requirements are not believed justified by the reliability benefits it would provide.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0

Dislikes 0

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer

Document Name

Comment

Black Hills Corporation agrees with comments from NAGF and EEI, included here:

The NAGF notes that Project 2021-04 needs to be closely coordinated with other active NERC IBR related projects to ensure there is no conflict and/or duplication of efforts. The NAGF recommends that NERC publish a guideline/roadmap to demonstrate how all the on-going and pending IBR work activities fit together so that industry can understand how these efforts will enhance BPS/BES reliability. For example, why is it necessary for PRC-028 to be effective prior to other new IBR standards (i.e., PRC-029/PRC-030/PRC-031)?

EEI offers the following additional comments:

DDR Requirements for PRC-002 & PRC-028

EEI suggests that consideration should be given to modifying the requirements for dynamic Disturbance recording (DDR) equipment in both PRC-002 and PRC-028 in order to permit responsible entities to either install DDR equipment or Phasor Measurement Units (PMUs) since PMU equipment capture disturbance data at equal or better rates, and have the added benefit of synchronizing disturbance data from other locations utilizing existing network communications.

Data Retention Requirements for PRC-002 & PRC-028

EEI does not agree that the data retention requirements for PRC-002 (see Requirement R11 - 10 days) and PRC-028 (Requirement R7 – 20 days) should be different. Having two different data retention requirements for two Reliability Standards that have the exact same purpose is unjustified. Given the currently enforceable version of PRC-002 has a 10 day retention period, PRC-028 should have the same data retention period.

Reliability Coordinator Responsibilities for PRC-028

EEI suggests that the RC should be provided with oversight responsibilities for the placement of DDR equipment, even at IBR facilities. While EEI understands that the desire is to have DDR equipment at all IBR Facilities, as more of these facilities are added to the BPS, it is likely that there will be clusters of IBR facilities in some areas diminishing the need for this equipment at all of these facilities. We further note that the cost of this equipment is significant, and consideration should be given to the actual need and the RC would be the best judge to make this determination.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

NA

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPC thanks you for the opportunity to comment and has signed on to ACES comments.

It is unclear as to what constitutes a “ride-through operation” of an IBR Unit in R1.2 and R1.3. Is this intended to be a reference to “no trip zone” identified in PRC-024? If so, as PRC- 024 is not currently applicable to non-BES IBRs, how is this identified for those facilities? We believe additional guidance is needed for these requirements.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

For R8, it is not clear whether the CAP implementation referenced in the 2nd bullet item must be complete at the end of the 90 days specified in the R8 text. If so, what then is the difference in the first bullet (restoring the capability) and why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit?

In R9.5 does the request to extend the time provided refer to any changes made to an original CAP timeline? (there are no other deadlines for completing any R9 CAP)

In R1.2 and R1.3 remove the unneeded brackets [ ] surrounding “the effective date of this standard”.

CAPS documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment will accomplish the intent of R8 & R9. An audit can check to ensure that all broken equipment was handled properly.

What dictates a “ride-thru” event in R1? The IBR mode status?

Why is R2.2.1 needed to be the IBR Unit transformer HV side versus the LV side?

Based on research for the last ballot on the costs of having this on each feeder at a wind farm. This doesn't include solar IBRS. MRO NSRF estimates that the cost of installing DFR equipment on the high side of a pad mounted transformer at the base of a wind turbine in the last 10% of an existing wind turbine feeder will be $300-450k or 2-3 times the cost of installing the same equipment in an existing substation.

It is not understood what drives the 2 seconds length and the 64 samples/sec recording requirements. Existing FR equipment typically has a maximum recording time of 60 cycles and maximum of 16 or 32 samples/sec. Both of these are not consistent with similar requirements of PRC-002 (30 cycles & 16 samples/sec).

3.2 will be difficult to achieve for older IBRs. FR recording equipment will need to be added to meet this requirement. Meeting these requirements at the inverter/controller level will be challenging.

MRO NSRF recommends that the SDT reach out to various manufacturers to confirm the equipment capability and if any changes/updates that may be necessary for equipment can meet this requirement will become available.

MRO NSRF recommends that the SDT consider equipment limitation be introduced similar to PRC-024 where equipment limitation is allowed but adequately reported.

MRO NSRF recommends the SDT consider alternative methods/requirements be provided as an option for the equipment that are not capable of meeting the recording requirements. Refer to

PRC-025, Options 5a and 5b as an example, where 5b option was introduced to eliminate costly replacements.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	
Document Name	

Comment

RF appreciates the continued efforts of the SDT on this project.

RF recommends adding a justification for the addition of CSV file formats to PRC-002 R11 Part 11.4 to the Technical Rationale. RF also recommends considering whether the addition of CSV should be limited to Dynamic Disturbance Recording (DDR) data, with the use of COMTRADE remaining required for all Fault Recording (FR) data.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	
Document Name	

Comment

We recognize that IBR's pose a reliability risk and that being able to monitor the events and have in depth data for a trip is very important. However, the granularity of the information being required by PRC-028 does not seem to be in step with what PRC-002 is asking for. Could this data be captured by TOs who have a greater situational awareness?

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

The cost and burden of the proposed PRC-028 requirements are not believed justified by the reliability benefits it would provide.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	

Document Name	

Comment
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), the MRO NSRF, and the NAGF for question #5.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	
Document Name	

Comment

The following comments are for the PRC-002-5 standard:

1) Replace "Hydro-Québec Interconnection" with "Québec Interconnection".

2) Correct VSL table for R1 Moderate and High since the examples don't cover exactly 70% et 80%. Suggest replacing with"more than 70%, but less than or equal to 80%" for the Moderate VSL and "more than 60%, but less than or equal to 70%" for the high VSL.

3) Severe VSL E11 : should read "…provided the requested data more than 60 days" instead of "…failed to provide the requested data more than 60 calendar days".

4) Attachment 1 step 3: "If the list has 11 or fewer buses, proceed to step 7" should be moved to step 2 with the following text "If the resulting list has 11 or fewer buses, proceed to Step 7".

The following comments are for the PRC-028-1 standard:

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.

We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2020-02 (PRC-029) and 2023-02(PRC-030). Are we to understand that this is the recommended text for the facilities section in regards to the standards where IBRs are applicable and that the other projects will ensure consistent language use in line iwth the recent ROP and GO/GOP definition revisions?

Likes 0	
Dislikes 0	

Response

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE supports EEI comments submitted for question 5 regarding Data Retention Requirements for PRC-002 & PRC-028.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	

Did the standard drafting team consider CIP implications (risks)?	
Likes 0	
Dislikes 0	
Response	

Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

For PRC-028, R8, it is not clear whether the CAP implementation in the 2nd bullet item must be complete at the end of the 90-days specified in the R8 text. If so, what then is the difference in the first bullet (restoring the capability) and why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit?

In PRC-028, R9.5, does the request to extend the time provided refer to any changes made to an original CAP timeline? There are no other deadlines for completing any R9 CAP.

CAPs documentation specifications and submittals to the RE are purely administrative and should be removed from the requirements list. A simple requirement to fix any faulty equipment will accomplish the intent of PRC-028, R8 and R9. An audit can check to ensure that all broken equipment was handled properly.

What dictates a “ride-thru” event in PRC-028, R1, the IBR mode status? Clarity is recommended.

In PRC-028, R1.2 and R1.3 remove the unnecessary brackets “[]” surrounding the “effective date of this standard”.

PRC-028, R1.3 has an *“if capable of recording”* clause. If the inverter is incapable of recording certain data, does the SDT contemplate an “exemption process”?

Why does PRC-028, R2.2.1 need to be the IBR Unit transformer HV side versus the LV side?

Southern Company is in agreement with EEI, recommending that the IBR and IBR Unit definitions should be removed from PRC-002 and PRC-028 because the associated SAR does not provide this SDT with the authority to develop or adopt a definition that is currently unapproved. Moreover, once these definitions are approved and added to the Glossary of Terms there will be no need for inclusion of the definitions within these Reliability Standards.

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 RSC	
Answer	
Document Name	
Comment	
NPCC RSC supports the project.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	
Document Name	
Comment	
Eversource supports EEI's comment that the SDT should consider modifying the requirements for dynamic Disturbance recording (DDR) equipment in both PRC-002 and PRC-028 in order to permit responsible entities to either install DDR equipment or Phasor Measurement Units (PMUs) since PMU equipment capture disturbance data at equal or better rates, and have the added benefit of synchronizing disturbance data from other locations utilizing existing network communications.	
Likes 0	
Dislikes 0	

Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	
Comment	

The following comments are for the PRC-002-5 standard:

1) Replace "Hydro-Québec Interconnection" with "Québec Interconnection".

2) Correct VSL table for R1 Moderate and High since the examples don't cover exactly 70% et 80%. Suggest replacing with"more than 70%, but less than or equal to 80%" for the Moderate VSL and "more than 60%, but less than or equal to 70%" for the high VSL.

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The following comments are for the PRC-028-1 standard:

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.

We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2020-02 (PRC-029) and 2023-02(PRC-030). Are we to understand that this is the recommended text for the facilities section in regards to the standards where IBRs are applicable and that the other projects will ensure consistent language use?

Likes 0	

Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

The SDT needs to coordinate with other active IBR driven NERC Projects to avoid conflicts and duplications of requirements.

PRC-028 needs to align with PRC-002 in regards to synchronized clock accurracy within +/- 2 milliseconds vs. +/- 1 millisecond.

Also, data retention requirements in PRC-028 need to align with PRC-002 which has 10 days instead of 20 days.

The RC should have oversite of the placement of DDR equipment at IBR facilities as in PRC-002.

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

Including post-approval references (i.e. “the effective date of this standard”) should not be considered as appropriate. Essentially this is grandfathering in the operational and reliability risk of not having appropriate data. The use of “if capable of recording” will be a pivotal point to consider when reviewing equipment for grandfathered IBR Units. Should be noted that “capable” does not equate to non-implementation of recording which could be a choice. With feeder lengths and determination of feeder length varying, the 90% criteria will possibly exclude feeders and significant numbers of IBR Units. If one feeder is 10 miles long and two others at same Inverter-Based Resource are 8.9 miles long only one IBR unit with SER (per Parts 1.2/1.3)/FR (per Part 2.2) data will be required to be compliant on the 10 mile feeder. If that one IBR unit is offline, where is the risk being mitigated? To ensure compliance, CMEP staff will have to ascertain applicability based on the criteria within the Requirement (i.e., entities will have to have documentation explaining their determination.) Non-BES Inverter-Based Resources will be even more difficult to apply the criteria.

The Technical Rationale picture/examples are good and clearly show that only one IBR Unit will need disturbance monitoring data to be compliant. One IBR unit’s data may still not allow for detailed analysis of events. Would reconsider Example 3’s use of BES definition references in light of the definitions proposed for Inverter-Based Resources and IBR Units.

Based on the Technical Rationale, to evaluate compliance for IBR units for SER, FR, and DDR data Regional Entities must access event analysis data.

In PRC-002 there is a need to capture DDR for stability SOLs and Elements included in an IROL. Please confirm that the RC can identify those situations for BES and non-BES IBRs (without considering any commercial operation date limitations) which would require DDR installation. Those situations exist and the risk needs mitigated.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

IBR & Unit IBR Definitions:

The IBR and IBR Unit definitions should be removed from PRC-002 and PRC-028 because the associated SAR does not provide this SDT with the authority to develop or adopt a definition that is currently unapproved. Moreover, once these definitions are approved and added to the Glossary of Terms there will be no need for inclusion of the definitions within these Reliability Standards.

DDR Requirements for PRC-002 & PRC-028

EEI also suggests that consideration should be given to modifying the requirements for dynamic Disturbance recording (DDR) equipment in both PRC-002 and PRC-028 in order to permit responsible entities to either install DDR equipment or Phasor Measurement Units (PMUs) since PMU equipment capture disturbance data at equal or better rates, and have the added benefit of synchronizing disturbance data from other locations utilizing existing network communications.

Data Retention Requirements for PRC-002 & PRC-028

EEI does not agree that the data retention requirements for PRC-002 (see Requirement R11 - 10 days) and PRC-028 (Requirement R7 – 20 days) should be different. Having two different data retention requirements for two Reliability Standards that have the exact same purpose is unjustified. Given the currently enforceable version of PRC-002 has a 10 day retention period, PRC-028 should have the same data retention period.

Reliability Coordinator Responsibilities for PRC-028

EEI suggests that the RC should be provided with oversight responsibilities for the placement of DDR equipment, even at IBR facilities. While EEI understands that the desire is to have DDR equipment at all IBR Facilities, as more of these facilities are added to the BPS, it is likely that there will be clusters of IBR facilities in some areas diminishing the need for this equipment at all of these facilities. We further note that the cost of this equipment is significant, and consideration should be given to the actual need and the RC would be the best judge to make this determination.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: 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 provides the following:

As currently drafted, PRC-028 does not contain the methodology like PRC-002 to determine if SER/FR is required. However, the DT has added, "elements associated with IBRs with an aggregate nameplate rating of 20 MVA and connecting to a voltage greater than or equal to 60 kV." Therefore, PG&E agrees with EEI input that "Elements to non-BES IBR units and BES IBR units" is too broad and the manner with which EEI has clarified the facilities to which the standard is applicable.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	
Document Name	

Comment

TAL believes the threshold of 20MW for a facility to be required to install DDR equipment is going to put a lot of burden on the utilities with very little gain for the BES.

Likes 0	
Dislikes 0	

Response

Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk	
Answer	
Document Name	
Comment	
Minnesota Power supports MRO NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Megan Melham - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	

Capital Power supports the comments submitted by NAGF.

The NAGF notes that Project 2021-04 needs to be closely coordinated with other active NERC IBR related projects to ensure there is no conflict and/or duplication of efforts. The NAGF recommends that NERC publish a guideline/roadmap to demonstrate how all the on-going and pending IBR work activities fit together so that industry can understand how these efforts will enhance BPS/BES reliability. For example, why is it necessary for PRC-028 to be effective prior to other new IBR standards (i.e., PRC-029/PRC-030)?

In addition, for the proposed Requirement R8, it is not clear whether or not the CAP referenced in the 2nd bullet item must be complete at the end of the 90 days. If so, what then is the difference between that and the first bullet (restoring the capability). Also, why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit? Further, the CAPs documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment should accomplish the intent of R8 & R9.

The NAGF has the following comments\questions regarding Requirement R3:

• What is the driver for the 2 seconds length and the 64 samples/sec recording requirements? Existing FR equipment typically has a maximum recording time of 60 cycles and maximum of 16 or 32 samples/sec. The proposed recording requirements are not consistent with similar requirements of PRC-002 (30 cycles & 16 samples/sec).

• Requirement 3.2 will be difficult to achieve for older IBRs. FR recording equipment will need to be added to meet this requirement. Meeting these requirements at the inverter/controller level will be challenging.

• Did the SDT reach out to various manufacturers to confirm the equipment capability and more importantly, are the changes/updates available that can meet this requirement?

• Should equipment limitation be introduced as one of the requirements, similar to PRC-024 where equipment limitation is allowed but adequately reported? • Should an alternative method/requirement be provided as an option for equipment that is not capable of meeting the recording requirements? Refer to PRC-025, Options 5a and 5b as an example, where 5b option was introduced to eliminate costly replacements.

Likes 0	
Dislikes 0	

Response
David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment
None.

Likes 0	
Dislikes 0	

Response
Marty Hostler - Northern California Power Agency - 4

Answer	
Document Name	

Comment
None.

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

It is unclear as to what constitutes a “ride-through operation” of an IBR Unit in R1.2 and R1.3. Is this intended to be a reference to “no trip zone” identified in PRC-024? If so, as PRC-024 is not currently applicable to non-BES IBRs, how is this identified for those facilities? We believe additional guidance is needed for these requirements.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	

Comment

For R8, it is not clear whether the CAP implementation referenced in the 2nd bullet item must be complete at the end of the 90 days specified in the R8 text. If so, what then is the difference in the first bullet (restoring the capability) and why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit?

In R9.5 does the request to extend the time provided refer to any changes made to an original CAP timeline? (there are no other deadlines for completing any R9 CAP)

In R1.2 and R1.3 remove the unneeded brackets [ ] surrounding “the effective date of this standard”.

CAPS documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment will accomplish the intent of R8 & R9. An audit can check to ensure that all broken equipment was handled properly.

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It is not understood what drives the 2 seconds length and the 64 samples/sec recording requirements. Existing FR equipment typically has a maximum recording time of 60 cycles and maximum of 16 or 32 samples/sec. Both of these are not consistent with similar requirements of PRC-002 (30 cycles & 16 samples/sec).

3.2 will be difficult to achieve for older IBRs. FR recording equipment will need to be added to meet this requirement. Meeting these requirements at the inverter/controller level will be challenging.

PacifiCorp recommends that the SDT reach out to various manufacturers to confirm the equipment capability and if any changes/updates that may be necessary for equipment can meet this requirement will become available.

PacifiCorp recommends that the SDT consider equipment limitation be introduced similar to PRC-024 where equipment limitation is allowed but adequately reported.

PacifiCorp recommends the SDT consider alternative methods/requirements be provided as an option for the equipment that are not capable of meeting the recording requirements. Refer to PRC-025, Options 5a and 5b as an example, where 5b option was introduced to eliminate costly replacements.

Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	

On behalf of the SERC Generator Working Group:

- General comment: Should there be an assessment to determine which facilities this monitoring equipment should be installed on rather than just requiring for every IBR Unit
- R1: The data required in 1.2.1-4 and 1.3.1-4 are not currently available in all manufacturers
- R8: The two bullets say the same thing. Should it be that the CAP is submitted within 90 days and then implemented after? Otherwise implementing it within 90 days is the same as restoring the recording capability.

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	
Document Name	
Comment	

PRC-028-1 Requirement R4 requires a DDR for the MPT of every 20+ MVA IBR with a connection point at a voltage of 60kV or greater . It is unclear whether these DDR (at least for BES IBR) should be included in the DDR coverage calculation in PRC-002-5 Requirement R5 Part 5.2. The SRC recommends that PRC-002-5 Requirement R5 be revised to clarify if any or all or none of the DDRs required by PRC-028-1 Requirement R4 are required (or allowed) to be included in the minimum DDR coverage under PRC-002-5 Requirement R5 Part 5.2.

PRC-028-1 Requirement R3 does not place minimum triggering thresholds on neutral overcurrent (Part 3.1.3.1), AC phase overvoltage and undervoltage (Parts 3.1.3.2 and 3.2.3.1), or overfrequency or underfrequency (Part 3.2.3.2). Improper threshold settings have led to event data being unavailable in instances where it would have been valuable for analysis. The SRC recommends that minimum triggering thresholds be added to the requirements to ensure this data is captured reliably.

PRC-028-1 Requirement R7, Part 7.2 requires that data subject to Part 7.1 be provided to the requesting entity within 30 calendar days of a request, yet Part 7.1 only requires the data to be retrievable for a period of 20 calendar days. The SRC recommends that the period to provide data under Part 7.2 be half of the data retention period under Part 7.1. In response to data requests, SRC members have often received data that does not fully cover the requested timeframes or that is incomplete and missing information. Ensuring that the response period under Part 7.2 is half of the data retention period under Part 7.1 would allow time for these types of errors to be detected and corrected before the data retention period expires and the data is lost.

PRC-028-1 Requirement R1, Part 1.3 requires currently in operation IBR units to record certain data unless they are not "capable of recording." The SRC requests that the SDT clarify what it means for an IBR Unit to not be capable of recording the required data, as the proposed language could be read to include IBR Units that have the technical capability to record the required data, but failed to record the data due to a malfunction or due to being temporarily out of service.

Requirement R5 of PRC-002-5 Includes some unnecessary administrative compliance burdens. A GO with a 500+ MVA unit or 300+ MVA unit within a 1000 MVA plant should already know that they are required to install DDR without a specific RC requirement to provide notification of their DDR obligation.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI offer the following additional comments:

IBR & Unit IBR Definitions:

The IBR and IBR Unit definitions should be removed from PRC-002 and PRC-028 because the associated SAR does not provide this SDT with the authority to develop or adopt a definition that is currently unapproved. Moreover, once these definitions are approved and added to the Glossary of Terms there will be no need for inclusion of the definitions within these Reliability Standards.

DDR Requirements for PRC-002 & PRC-028

EEI also suggests that consideration should be given to modifying the requirements for dynamic Disturbance recording (DDR) equipment in both PRC-002 and PRC-028 in order to permit responsible entities to either install DDR equipment or Phasor Measurement Units (PMUs) since PMU equipment capture disturbance data at equal or better rates, and have the added benefit of synchronizing disturbance data from other locations utilizing existing network communications.

Data Retention Requirements for PRC-002 & PRC-028

EEI does not agree that the data retention requirements for PRC-002 (see Requirement R11 - 10 days) and PRC-028 (Requirement R7 – 20 days) should be different. Having two different data retention requirements for two Reliability Standards that have the exact same purpose is unjustified. Given the currently enforceable version of PRC-002 has a 10 day retention period, PRC-028 should have the same data retention period.

Reliability Coordinator Responsibilities for PRC-028

EEI suggests that the RC should be provided with oversight responsibilities for the placement of DDR equipment, even at IBR facilities. While EEI understands that the desire is to have DDR equipment at all IBR Facilities, as more of these facilities are added to the BPS, it is likely that there will be clusters of IBR facilities in some areas diminishing the need for this equipment at all of these facilities. We further note that the cost of this equipment is significant, and consideration should be given to the actual need and the RC would be the best judge to make this determination.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 5,6

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

In previous response to comments, the drafting team suggested that “FERC Order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.” In fact, FERC Order 901 states that the more limited approach taken in PRC-002 “[has] been adequate to provide the data necessary to analyze major system events in the past.” Invenergy recommends the SDT develop a methodology similar to PRC-002 Attachment 1 that Transmission Owners and Reliability Coordinators can utilize to identify key nodes where disturbance monitoring equipment should be deployed.

The SER data required in R1.2.1. and R1.2.2. is generic and should be refined to target specific categories of fault codes and alarms so as not to overburden local storage of the data. On that point, 20 days of retrievable data is simply beyond the capabilities of some inverters. Invenergy recommends the data storage requirement in R7.1. be reduced to 10 days to align with PRC-002 R11.1. Furthermore, the various requested IBR Unit level data, sampling rates, time sync, and data format present many technical challenges for existing IBRs, some of which will have no solution other than replacement of the IBR Unit. As such, we suggested changes to R9 to account for these equipment limitations in response to Question 4.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

The NAGF notes that Project 2021-04 needs to be closely coordinated with other active NERC IBR related projects to ensure there is no conflict and/or duplication of efforts. The NAGF recommends that NERC publish a guideline/roadmap to demonstrate how all the on-going and pending IBR work activities fit together so that industry can understand how these efforts will enhance BPS/BES reliability. For example, why is it necessary for PRC-028 to be effective prior to other new IBR standards (i.e., PRC-029/PRC-030)?

In addition, for the proposed Requirement R8, it is not clear whether or not the CAP referenced in the 2nd bullet item must be complete at the end of the 90 days. If so, what then is the difference between that and the first bullet (restoring the capability). Also, why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit? Further, the CAPs documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment should accomplish the intent of R8 & R9.

The NAGF has the following comments\questions regarding Requirement R3:

- *What is the driver for the 2 seconds length and the 64 samples/sec recording requirements? Existing FR equipment typically has a maximum recording time of 60 cycles and maximum of 16 or 32 samples/sec. The proposed recording requirements are not consistent with similar requirements of PRC-002 (30 cycles & 16 samples/sec).*
- *Requirement 3.2 will be difficult to achieve for older IBRs. FR recording equipment will need to be added to meet this requirement. Meeting these requirements at the inverter/controller level will be challenging.*
- *Did the SDT reach out to various manufacturers to confirm the equipment capability and more importantly, are the changes/updates available that can meet this requirement?*
- *Should equipment limitation be introduced as one of the requirements, similar to PRC-024 where equipment limitation is allowed but adequately reported?*
- *Should an alternative method/requirement be provided as an option for equipment that is not capable of meeting the recording requirements? Refer to PRC-025, Options 5a and 5b as an example, where 5b option was introduced to eliminate costly replacements.*

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	
Comment	

Overall wording for the sections mentioned above for PRC-028 should be cleaned up. Terms like IBR should have formal definitions, outside of PRC-028 in the NERC Glossary of Terms.

Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5,6

Answer	
Document Name	
Comment	

In previous response to comments, the drafting team suggested that “FERC Order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.” In fact, FERC Order 901 states that the more limited approach taken in PRC-002 “[has] been adequate to provide the data necessary to analyze major system events in the past.” Invenergy recommends the SDT develop a methodology similar to PRC-002 Attachment 1 that Transmission Owners and Reliability Coordinators can utilize to identify key nodes where disturbance monitoring equipment should be deployed.

The SER data required in R1.2.1. and R1.2.2. is generic and should be refined to target specific categories of fault codes and alarms so as not to overburden local storage of the data. On that point, 20 days of retrievable data is simply beyond the capabilities of some inverters. Invenergy recommends the data storage requirement in R7.1. be reduced to 10 days to align with PRC-002 R11.1. Furthermore, the various requested IBR Unit level data, sampling rates, time sync, and data format present many technical challenges for existing IBRs, some of which will have no solution other than replacement of the IBR Unit. As such, we suggested changes to R9 to account for these equipment limitations in response to Question 4.

Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2021-04 Modifications to PRC-002 – Phase II | Draft 2
Comment Period Start Date:	3/18/2024
Comment Period End Date:	4/11/2024
Associated Ballot(s):	2021-04 Modifications to PRC-002 – Phase II Implementation Plan AB 2 OT 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 | Non-Binding Poll AB 2 NB 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 AB 2 ST 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll AB 2 NB 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 AB 2 ST

There were 73 sets of responses, including comments from approximately 173 different people from approximately 115 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, Soo Jin Kim (via email) or at (404) 446-9742.

Questions

1. Do you agree with the modification in "Applicability, Section 4.2. Facilities" in PRC-002-5 and PRC-028-1?

2. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

3. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

4. Do you agree with introduction of Requirement R9 in PRC-028-1 requiring Entities of an applicable facility that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance to develop, maintain, and implement a Corrective Action Plan?

5. 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
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO

					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities- Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF

					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Southern Company - Alabama Power Company	Colby Galloway	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	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
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
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
					Kris Carper	Arizona Electric Power Cooperative, Inc.	2	WECC

					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Scott Berry	Wabash Valley Power Association	3	RF
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Jasmine Morris	Southern Maryland Electric Cooperative	3	RF
Eversource Energy	Joshua London	1,3		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Electric Reliability Council of Texas, Inc.	Kennedy Meier	2		ISO/RTO Council Standards Review Committee (SRC)	Darcy O'Connell	California ISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Joshua Phillips	Southwest Power Pool, Inc. (RTO)	2	MRO
					Helen Lainis	Independent Electricity System Operator	2	NPCC

					John Pearson	ISO New England, Inc.	2	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Thomas Foster	PJM Interconnection, L.L.C.	2	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
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
					Tyler Brun	Pacific Gas and Electric Company	5	WECC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC

Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
Randy Buswell	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
Randy MacDonald	New Brunswick Power Corporation	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	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

					Joshua London	Eversource Energy	1	NPCC
Elevate Energy Consulting	Ryan Quint	NA - Not Applicable	NA - Not Applicable	Elevate Energy Consulting	Ryan Quint	Elevate Energy Consulting		NA - Not Applicable
					N/A	N/A		NA - Not Applicable
Ryan Strom	Ryan Strom		RF	Buckeye Power Group	Carl Spaetzel	Buckeye Power, Inc.	3	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Zemanek	Buckeye Power, Inc.	5	RF
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Stephen Whaite	Stephen Whaite		RF	ReliabilityFirst Ballot Body	Lindsey Mannion	ReliabilityFirst	10	RF

				Member and Proxies	Stephen Whaite	ReliabilityFirst	10	RF
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the modification in “Applicability, Section 4.2. Facilities” in PRC-002-5 and PRC-028-1?

Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting

Answer	No
Document Name	

Comment

The applicability section of PRC-028-1 uses “BES” and then “Non-BES” and it is unclear why the SDT could not simply say Registered IBR, since the section is essentially duplicating the definition of Registered IBR pursuant to the changes in the ROP. Furthermore, the language does not appear to exactly match those changes and uses the phrase “that either have or contribute to an aggregate…” which seems vague. Therefore, we recommend developing a more straightforward and effective approach to defining this applicability rather than slightly modifying and using redundant language as compared to the ROP.

Likes 0

Dislikes 0

Response

Thank you for your comment. The phrase “that either have or contribute to an aggregate…” came directly from the latest version of the NERC ROP registration criteria for GO/GOP approved by the NERC Board of Trustees (Board) in February and filed with FERC on March 19, 2024. However, the language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy supports and recommends implementation of EEI provided comments.

Additionally, Duke Energy recommends changing PRC-028-1 Applicability - 4.2 from "a voltage greater than or equal to 60 kV" to "a voltage greater than or equal to 40 kV" to capture a larger aggregate of resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The applicability was based on the latest version of the NERC Rules of Procedure (ROP) registration criteria for GO/GOP, and the intent was to include registered IBRs. IBRs connected at 40kV do not meet that registration threshold. However, the language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the ROP revision process. See also response to EEI comments.	
Robert Follini - Avista - Avista Corporation – 3	
Answer	No
Document Name	
Comment	
No objection to the applicability for PRC-002-5. However the language for PRC-028-1 the scope of what is applicable and what isnt for IBRs needs clarification. Also, the PRC-028 defines IBR which isn't in the NERC Glossary of Terms. It would be preferable to have this term defined before use in the PRC-028 standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Applicability section has been edited and reformatted for clarity in the next draft, and the language used will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Glen Farmer - Avista - Avista Corporation – 5	
Answer	No

Document Name	
Comment	
No objection to the applicability for PRC-002-5. However the language for PRC-028-1 the scope of what is applicable and what isnt for IBRs needs clarification. Also, the PRC-028 defines IBR which isn't in the NERC Glossary of Terms. It would be preferable to have this term defined before use in the PRC-028 standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Applicability section has been edited and reformatted for clarity in the next draft, and the language used will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	No
Document Name	
Comment	
NRG agrees with NAGF's comments concerning applicability language. The language proposed for applicability to PRC-002 is acceptable but not with regards to language proposed for PRC-028. NRG supports NAGF's comments that this needs to"*align with the pending NERC Glossary of Terms GO/GOP definition revisions*".	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to NAGF comments.	
Marcus Bortman - APS - Arizona Public Service Co. – 6	

Answer	No
Document Name	
Comment	
AZPS supports the proposed language contained in the Applicabiity section for PRC-002-5. However, we do not support the proposed language contained in the Applicability section of PRC-028-1 because the phrase “The Elements associated with” is too broad and subjective. AZPS would support the language if that phrase was removed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has removed “The Elements associated with” from the Applicability section of the next draft of PRC-028.	
Ben Hammer - Western Area Power Administration – 1	
Answer	No
Document Name	
Comment	
For PRC-002, yes. For PRC-028, no. There is no filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Some engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion rather than requiring every site to install DME.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared.	
Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	

Buckeye Power supports the comments made by ACES:

We at ACES appreciate the efforts of the SDT to deal with the nebulous topic that is IBRs. It is certainly a difficult task to create a new Reliability Standard and carefully craft the language thereof. We see no issue with the update to Section 4.2 of PRC-002-5 draft 2 and in fact appreciate the SDT’s conciseness in this area. However, we do have several concerns with Section 4 of PRC-0028-1 draft 2. It is our opinion that taking a blanket approach for TOs with respect to non-BES IBRs creates confusion, is not in line with the latest revisions to the NERC Rules of Procedure, and represents an unreasonable level of compliance scope creep.
It is our opinion that requiring the TO to install monitoring equipment on non-BES Elements is contradictory to the scope of the TO in the NERC Rules of Procedure. We believe that the role of the TO should be limited to Facilities as defined in the NERC Glossary of Terms (i.e., BES only).
As stated in the Technical Rationale, “It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an IBR generating facility.” As this is an uncommon occurrence, we do not believe that exceeding the scope of the TO’s registration represents any significant reduction in risk to the BES. Therefore, we recommend modifying Section 4 of PRC-028-1 as follows:
4. Applicability:
4.1 Functional Entities:
4.1.1 Transmission Owner that owns equipment as identified in section 4.2.1.
4.1.2 Generator Owner that owns equipment identified in section 4.2.
4.2 Facilities:
4.2.1 Elements associated with a BES Inverter-Based Resource(s)
4.2.2 Elements associated with a non-BES Inverter-Based Resource(s) that is:

4.2.2.1 Connected to the Bulk Power System, and 4.2.2.2 Meets the criteria for a Category 2 GO facility.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to ACES comments.	
Kimberly Turco - Constellation – 6	
Answer	No
Document Name	
Comment	
Including non-BES IBRs for PRC-028-1 could present additional financial difficulties that might cause some GOs to consider other options. Due to the expenses of NERC Registry and PRC-028 requirements, non-BES IBR facilities could possibly be shut-down rather than meet the upcoming NERC requirements. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No

Document Name	
Comment	

Black Hills Corporation agrees with NAGF comments. NAGF supports the "Applicability, Section 4.2. Facilities" language proposed for PRC-002-5. The NAGF does not support the "Applicability, Section 4.2. Facilities" language proposed for PRC-028-1. The NAGF notes that the language for PRC-028-1 needs to align with the pending NERC Glossary of Terms GO/GOP definition revisions and therefore, recommend that the PRC-028-1 "Applicability, Section 4.2. Facilities" language be revised as follows:

"4.1.1. Transmission Owner that owns equipment as identified in Facilities section

4.1.2. Generator Owner that owns equipment as identified in Facilities section

Facilities: The Elements associated with (1) BES Inverter-Based Resources; (2) – to be defined and align with the pending NERC Glossary of Terms GO/GOP definition revisions."

Additionally, Black Hills Corporation agrees with the following comment from EEI:

IBR & Unit IBR Definitions:

The IBR and IBR Unit definitions should be removed from PRC-002 and PRC-028 because the associated SAR does not provide this SDT with the authority to develop or adopt a definition that is currently unapproved. Moreover, once these definitions are approved and added to the Glossary of Terms there will be no need for inclusion of the definitions within these Reliability Standards.

Likes 0	
Dislikes 0	
Response	
Thank you. Please see responses to NAGF & EEI comments.	
Donna Wood - Tri-State G and T Association, Inc. – 1	
Answer	No
Document Name	

Comment	
Tri-State agrees with MRO Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see responses to MRO Comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. – 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments:

We at ACES appreciate the efforts of the SDT to deal with the nebulous topic that is IBRs. It is certainly a difficult task to create a new Reliability Standard and carefully craft the language thereof. We see no issue with the update to Section 4.2 of PRC-002-5 draft 2 and in fact appreciate the SDT's conciseness in this area. However, we do have several concerns with Section 4 of PRC-0028-1 draft 2. It is our opinion that taking a blanket approach for TOs with respect to non-BES IBRs creates confusion, is not in line with the latest revisions to the NERC Rules of Procedure, and represents an unreasonable level of compliance scope creep.

It is our opinion that requiring the TO to install monitoring equipment on non-BES Elements is contradictory to the scope of the TO in the NERC Rules of Procedure. We believe that the role of the TO should be limited to Facilities as defined in the NERC Glossary of Terms (i.e., BES only).

As stated in the Technical Rationale, "It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an IBR generating facility." As this is an uncommon occurrence, we do not believe that exceeding the scope of the TO's registration represents any significant reduction in risk to the BES. Therefore, we recommend modifying Section 4 of PRC-028-1 as follows:

4. Applicability: 4.1 Functional Entities: 4.1.1 Transmission Owner that owns equipment as identified in section 4.2.1. 4.1.2 Generator Owner that owns equipment identified in section 4.2. 4.2 Facilities: 4.2.1 Elements associated with a BES Inverter-Based Resource(s) 4.2.2 Elements associated with an non-BES Inverter-Based Resource(s) that is: 4.2.2.1 Connected to the Bulk Power System, and 4.2.1.14.2.2.2 Meets the criteria for a Category 2 GO facility.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see responses to ACES comments.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

For PRC-002, yes. For PRC-028, no. There is no filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Some engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion rather than requiring every site to install DME.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Thank you for your comment. This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see responses to MRO NSRF and NAGF comments.	
Alison MacKellar - Constellation – 5	
Answer	No
Document Name	

Comment	
Including non-BES IBRs for PRC-028-1 could present additional financial difficulties that might cause some GOs to consider other options. Due to the expenses of NERC Registry and PRC-028 requirements, non-BES IBR facilities could possibly be shut-down rather than meet the upcoming NERC requirements. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), the MRO NSRF, and the NAGF for question #1.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see responses to EEI, MRO NSRF, and NAGF comments.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	No
Document Name	
Comment	
No, CenterPoint Energy Houston Electric, LLC (CEHE) supports Edison Electric Institute (EEI) comments submitted for question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to EEI comments.	
Daniel Gacek - Exelon – 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question. Additionally, PRC-028, Section 4.2 the wording should be modified to define equal to or greater than 20MVA (and/or?) connected to a common point equal to or greater than 60kV. The proposed wording is ambiguous.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language used in the Applicability section of the next draft has been revised and will not include the non-BES IBRs affected by the Rules of Procedure revision process. Also, see response to EEI comments.	
Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	No
Document Name	
Comment	
Southern Company is in agreement with EEI and does not support the language contained in the Applicability section of PRC-028-1 because the phrase “The Elements associated with” is too broad and subjective. To address this concern, we suggest deleting that phrase (see below). Facilities: [***The Elements associated with]*** **REMOVE...** (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. In addition, Southern Company recommends the applicability section in PRC-028, should include a clause for filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion (risk-based approach) rather than requiring every site to install DME. Southern agrees with the Applicability changes proposed in PRC-002-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT has removed “The Elements associated with” from the Applicability section of the next draft of PRC-028. The purpose and requirements of PRC-002 and PRC-028 cannot be directly compared. This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. Also, see response to EEI comments.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	

Southern Indiana Gas & Electric, Company (SIGE) supports Edison Electric Institute (EEI) comments submitted for question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you. See the response to EEI comments.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
EEI does not object to the proposed language contained in the Applicability section for PRC-002-5, however, we do not support the language contained in the Applicability section of PRC-028-1 because the phrase “The Elements associated with” is too broad and subjective. To address this concern, we suggest deleting that phrase (see below). Facilities: **The Elements associated with** (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT has removed “The Elements associated with” from the Applicability section of the next draft of PRC-028.	

Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	
Comment	
:PG&E agrees with the changes to PRC-002 which explicitly exclude IBRs from the standard. PG&E does not agree with the changes to PRC-028-1 Applicability, Section 4.2 Facilities. PG&E concurs with the EEI comments which indicated they do not agree with the proposed language contained in the Applicability section of PRC-028-1 for the following reasons: 1 - Given the voltage identified with Non-BES IBRs, DPs should be added to the Functional Entities section. 2 - Applying the phrase all Elements to non-BES IBR units is too broad and subjective for use with these resources. 3 - Clarity is needed as to what is and is not in scope for IBR resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See the response to EEI comments. 1 – The language used in the Applicability section of the next draft has been revised and will not include the non-BES IBRs affected by the Rules of Procedure revision process. 2 – PRC-028 does not use the phrase “all Elements”, but the phrase “The Elements associated with” has been removed from the Applicability section of the next draft of the standard. 3 – The Applicability section has been edited and reformatted for clarity in the next draft, and the language used will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Kinte Whitehead - Exelon - 3	

Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question. Additionally, PRC-028, Section 4.2 the wording should be modified to define equal to or greater than 20MVA (and/or?) connected to a common point equal to or greater than 60kV. The proposed wording is ambiguous.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The language used in the Applicability section of the next draft has been revised and will not include the non-BES IBRs affected by the Rules of Procedure revision process. Also, see response to EEI comments.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
The threshold of 20MW seems low and would create additional burden on the utilities to have to install all the equipment to monitor what is being required.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language used in the Applicability section of the next draft has been revised. It will not include the non-BES IBRs affected by the Rules of Procedure revision process.	

Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. See the response to the MRO NSRF comments.	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the comments submitted by NAGF. Capital Power does not agree with the modification in "Applicability, Section 4.2. Facilities" for PRC-028-1. The language for PRC-028-1 needs to align with the pending NERC Glossary of Terms GO/GOP definition revisions. Capital Power recommends that the PRC-028-1 "Applicability, Section 4.2. Facilities" language be revised as follows: 4.1.1. Transmission Owner that owns equipment as identified in Facilities section 4.1.2. Generator Owner that owns equipment as identified in Facilities section **Facilities:** The Elements associated with (1) BES Inverter-Based Resources; (2) to be defined and align with the pending NERC Glossary of Terms GO/GOP definition revisions. Capital Power agrees with the modification in "Applicability, Section 4.2. Facilities" for PRC-002-5.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process. Also see response to NAGF comments.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
For PRC-002, yes. For PRC-028, no. There is no filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Some engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion rather than requiring every site to install DME.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	

Comment
We at ACES appreciate the efforts of the SDT to deal with the nebulous topic that is IBRs. It is certainly a difficult task to create a new Reliability Standard and carefully craft the language thereof. We see no issue with the update to Section 4.2 of PRC-002-5 draft 2 and in fact appreciate the SDT's conciseness in this area. However, we do have several concerns with Section 4 of PRC-0028-1 draft 2. It is our opinion that taking a blanket approach for TOs with respect to non-BES IBRs creates confusion, is not in line with the latest revisions to the NERC Rules of Procedure, and represents an unreasonable level of compliance scope creep. It is our opinion that requiring the TO to install monitoring equipment on non-BES Elements is contradictory to the scope of the TO in the NERC Rules of Procedure. We believe that the role of the TO should be limited to Facilities as defined in the NERC Glossary of Terms (i.e., BES only). As stated in the Technical Rationale, "It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an IBR generating facility." As this is an uncommon occurrence, we do not believe that exceeding the scope of the TO's registration represents any significant reduction in risk to the BES. Therefore, we recommend modifying Section 4 of PRC-028-1 as follows: 4. Applicability: 4.1 Functional Entities: 4.1.1 Transmission Owner that owns equipment as identified in section 4.2.1. 4.1.2 Either of the following Generator Owner types that owns equipment identified in section 4.2:. 4.1.1.1 Category 1 Generator Owner 4.1.1.1 Category 2 Generator Owner 4.2 Facilities: Elements associated with either of the following facility types: 4.2.1 Elements associated with a BES Inverter-Based Resource(s) connected to the Bulk Electric System

4.2.2 Elements associated with an non-BES Inverter-Based Resource(s) that is: 4.2.2.1 cConnected to the Bulk Power System, that and 4.2.2.2 mMeets the criteria for a Category 2 GO facility.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The language used in the Applicability section of the next draft has been revised and will not include the non-BES IBRs affected by the Rules of Procedure revision process.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
For PRC-002, yes. For PRC-028, no. There is no filtering or high impact assessment of the wide-open applicability scope of the facilities in Section 4.2 as there is in PRC-002 for synchronous units. Some engineering assessment is needed to determine which subset of IBR facilities may be the critical sites based on location, vendor susceptibility to trouble, or some other valid criterion rather than requiring every site to install DME.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	

Answer	No
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) asks the SDT to clarify Figure 1 in the PRC-002-5 Technical Rationale (page 2) to ensure adequate data is available to facilitate analysis of Bulk Electric System (BES) Disturbances. Currently, the title for Figure 1: "Example to Clarify Applicability of PRC-002 Versus PRC-028" uses the word "versus" which seems to denote only one or the other standard is applicable. Therefore, the SRC asks the SDT to clarify Figure 1 and the supporting text to clearly indicate that data relative to breaker #3 is subject to both PRC-002-5 and PRC-028-1. This will serve to illustrate that Facilities that are part of protection schemes that overlap with Facilities covered by PRC-028-1 are not automatically excluded from PRC-002 applicability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent of Figure 1 in the PRC-002-5 Technical Rationale is to illustrate that breaker 3 *is only* applicable to PRC-028 as an element associated with a registered IBR. This SDT has been careful to avoid setting up a situation of double jeopardy for registered entities with PRC-002 and PRC-028.	
Patricia Ireland - DTE Energy - 4	
Answer	No
Document Name	
Comment	
For PRC-028 section 4.2: 20 MVA is too low of a diminimus. With this facility definition, implementation of this standard will be unduly burdensome	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The language used in the Applicability section of the next draft has been revised and will not include the non-BES IBRs affected by the Rules of Procedure revision process.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not object to the proposed language contained in the Applicability section for PRC-002-5, however, we do not support the language contained in the Applicability section of PRC-028-1 because the phrase "The Elements associated with" is too broad and subjective. To address this concern, we suggest deleting that phrase (see below). **Facilities:** (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The phrase "The Elements associated with" has been deleted from the next draft of PRC-028.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	

The Applicability section would benefit from simplification and alignment with the other IBR-focused standards in development. As currently drafted, PRC-028-1, PRC-029-1, and PRC-030-1 all use different language to describe the same applicable Facilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process. The other standards referenced in your comment will likely follow similar format in upcoming revisions.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF supports the "Applicability, Section 4.2. Facilities" language proposed for PRC-002-5. The NAGF does not support the "Applicability, Section 4.2. Facilities" language proposed for PRC-028-1. The NAGF notes that the language for PRC-028-1 needs to align with the pending NERC Glossary of Terms GO/GOP definition revisions and therefore, recommend that the PRC-028-1 "Applicability, Section 4.2. Facilities" language be revised as follows: *"4.1.1. Transmission Owner that owns equipment as identified in Facilities section* *4.1.2. Generator Owner that owns equipment as identified in Facilities section* ***Facilities:** The Elements associated with (1) BES Inverter-Based Resources; (2) – to be defined and align with the pending NERC Glossary of Terms GO/GOP definition revisions."*	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
No objection to the applicability for PRC-002-5. However, in the language for PRC-028-1 the scope of what is applicable and what isn't for IBRs needs clarification. Also, the PRC-028 defines IBR which isn't in the NERC Glossary of Terms. It would be preferable to have this term defined before use in the PRC-028 standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Applicability section has been edited and reformatted for clarity in the next draft, and the language used will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
The Applicability section would benefit from simplification and alignment with the other IBR-focused standards in development. As currently drafted, PRC-028-1, PRC-029-1, and PRC-030-1 all use different language to describe the same applicable Facilities.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process. The other standards referenced in your comment will likely follow similar format in upcoming revisions.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
If there is a small IBR resource (<20MVA) that is connected on a collector system that connects into a >=60kV system, it wouldn’t fall under PRC-028. If a few years later a separate entity connects another IBR-based resource on that same system that brings the aggregate MVA above the threshold of 20MVA, how would the original GO know that they now fall under the PRC-028 standard?	

Similarly, if there are multiple separate entities sharing a common point of interconnect on a >=60kV system and they each contribute to a >=20MVA aggregate, is it the expectation that each of these GOs be familiar enough with the surrounding system and generation resources to know that they fall under the requirements of this new standard? Specific to PRC-028-1 R2.1., if fault recording data is measured on the high-side of the main power transformer, current injected by the inverters may be swamped out by ground current from the main power transformer for ground faults on the transmission system if the main power transformer is configured to be a ground source for transmission faults. This has been observed at IBR plants connected to Idaho Power's system. If the goal is to record plant-level current injected by the inverters, we recommend changing R2.1 to obtain FR data at the low-side of the main power transformer. These are all challenges that could develop, if not addressed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and your comments. Your first two questions are outside the scope of this SDT and would be better addressed through the NERC IBR Registration Initiative as they deal with the latest version of the NERC ROP registration criteria for GO/GOP approved by the NERC Board in February and filed with FERC on March 19, 2024. Your concern with PRC-028-1 R2.1 is addressed in the "Rationale for Requirement 2" section of the PRC-028 Technical Rationale beginning on page 7.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP agrees with the modification of the Applicability sections, we believe it would provide consistency across standards if the BPS registration criteria was referenced for the applicable IBR entities. For example, in the most recent draft of PRC-029, they simply point to the	

BPS registration criteria. Might that be considered here also? If all standards are to meet the FERC 901 order, this might be an idea to consider.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. The language used in the Applicability section of the next draft has been revised. It will not include the non-BES IBRs affected by the Rules of Procedure revision process. The other standards referenced in your comment will likely follow similar format in upcoming revisions.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation agrees with the PRC-002-5 but PRC-028 does not apply to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. See response to EEI comments.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marty Hostler - Northern California Power Agency - 4	
Answer	Yes
Document Name	
Comment	
YES	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
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.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 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.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends revising Section 4.2 Facilities in proposed PRC-028-1 to clarify that both Elements at either BES Inverter-Based Resources or non-BES Inverter-Based resources as described are not required, but the scenario of either or both could exist. Texas RE proposes the following verbiage: 4.2. Facilities 4.2.1 The Elements associated with BES Inverter-Based Resources 4.2.2 The Elements associated with Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The Applicability section has been edited and reformatted for clarity in the next draft. The phrase "The Elements associated with" has been deleted from the Facilities section, because the elements are clarified in the body of the standard. The language used will not include the non-BES IBRs affected by the Rules of Procedure revision process.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
WECC has no comments on PRC-002-5. For PRC-028-1, the use of the term "Element" to describe Facilities included per "Applicability, Section 4.2 Facilities" may confuse industry as the definition of Facility references "single" BES Element. Consider dropping the phrase "The Elements associated with" as the Requirements dictate which equipment is in scope (and the "Functional Entities" section mention equipment. Would consider saying for 4.1.1 and 4.1.2 "..that owns Facilities as identified in section 4.2." to provide more clarification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Applicability section has been edited and reformatted for clarity in the next draft. The phrase "The Elements associated with" has been deleted.	

2. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

Rhonda Jones - Invenergy LLC - 5,6

Answer	No
Document Name	

Comment

NERC has not provided any cost benefit analysis to suggest PRC-028 will provide a reliability benefit commensurate with the significant costs expected to be paid by applicable Generator Owners.

Likes 0	
Dislikes 0	

Response

This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

Cannot determine cost effectiveness.

Likes 0	
Dislikes 0	

Response

This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF notes that requiring data monitoring equipment at all IBR facilities is unnecessary and an excessive cost burden for existing IBR facility owners to bear which may lead to unintended adverse impacts to reliability. *The NAGF requests additional clarification regarding the language "if capable of recording" used in Requirement 1.3 to better understand the cost impacts of the proposed PRC-028-1.*	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
SPP has a concern about the applicability of this question.	

In reference to PRC-002, the drafting team has not provided any analytical data to show industry the potential of any cost to implement this standard. We understand that there were some non-substantive changes in the standard that would suggest no major cost. From our perspective, the question can't be answered about cost effectiveness when there is no data to review.

Additionally, the implementation plan for PRC-028 states that the standard will need various phase-in dates for the standard; however, there is no data to show what the cost will be to implement changes in reference to addressing industry's compliance need. Some type of cost analysis report should be produced to help industry measure concerns like man hours as well as installation of equipment from a compliance perspective.

SPP recommends that the drafting team provide information on cost-effectiveness (if equipment installation is required and/or man hours required to implement) to help them get a better understanding of the implementation cost and the opportunity to provide quality feedback to NERC in reference to cost effectiveness.

Likes 0	
Dislikes 0	

Response

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Colin Chilcoat - Invenergy LLC - 5,6

Answer	No
Document Name	

Comment

NERC has not provided any cost benefit analysis to suggest PRC-028 will provide a reliability benefit commensurate with the significant costs expected to be paid by applicable Generator Owners.

Likes 0	
Dislikes 0	

Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	No
Document Name	
Comment	
The SDT has not provided a cost estimate nor tangible reliability indices improvements said modifications are projected to provide. No standard should be allowed if a cost/benefit analysis is not provided by the SDT. SDT frequently asks this question but never provides a cost/benefit justification. SDTs and others, usually simply says there is a reliability gap, or a risk, but does not provide estimated, tangible, reliability indices improvement numbers or a cost estimate to fill the alleged gap or risk.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Patricia Ireland - DTE Energy - 4	
Answer	No
Document Name	
Comment	
Meeting the PRC-028 monitoring requirements will involve the installation of expensive monitoring equipment at locations with minimal impact on the BES	

Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Requiring DME equipment at all IBR facilities will be excessively costly compared to the value having the equipment. It is hard to believe that every single IBR site needs to have this equipment installed.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement.	

As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we strongly disagree with making this new standard inclusive of all applicable IBR facilities **regardless of risk to the BES**. In the opinion of ACES, a blanket approach requiring every applicable IBR facility to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which IBR facilities would provide the most benefit to the BES, before selectively adding such capabilities. In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach as is done in PRC-002-5.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO. The SDT has not provided a cost estimate nor tangible reliability indices improvements said modifications are projected to provide. No standard should be allowed if a cost/benefit analysis is not provided by the SDT. SDT frequently asks this question but never provides a cost/benefit justification. SDTs and others, usually simply says there is a reliability gap, or a risk, but does not provide estimated, tangible, reliability indices improvement numbers or a cost estimate to fill the alleged gap or risk.	
Likes 0	
Dislikes 0	
Response	

This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Requiring DME equipment at all IBR facilities will be excessively costly compared to the value having the equipment. It is hard to believe that every single IBR site needs to have this equipment installed.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the comments submitted by NAGF. Capital Power notes that requiring data monitoring equipment at all IBR facilities is unnecessary and an excessive cost burden for existing IBR facility owners to bear which may lead to unintended adverse impacts to reliability. PRC-028-1 creates a more restrictive requirement on IBR facilities for data monitoring than for synchronous generation facilities. The requirement for data monitoring equipment should align between the two types of generating resources by requiring the TOP or applicable RE to indicate that monitoring equipment is necessary for the IBR facility.	

Additional clarification regarding the language “if capable of recording” used in Requirement 1.3 is requested to better understand the cost impacts of the proposed PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	

The threshold of 20MW seems low and would create additional burden on the utilities to have to install all the equipment to monitor what is being required.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
PRC-028 should follow PRC-002 with criteria to filter the BES Elements required to provide SER and FR data, as well as DDR data. The cost of all IBR facilities providing this data seems excessive without some analysis first of which sites will provide the most benefit. Capturing all fault codes and all fault alarms under requirements R1.2 and R1.3 will also not provide much benefit vs. the cost.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	

Comment	
The modifications include existing IBRs now and require monitoring specific elements that may be costly to implement especially for the units that are at a distance greater then or equal to 90% of the longest collector feeder. The proposed requirements for IBRs that will be installed are reasonable as new sites can be built to include that monitoring.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company does not agree that the modifications are cost effective. For PRC-028-1, requiring DME equipment at all IBR facilities does not comport with the NERC risk-based approach. To incorporate an informed, risk-based approach to reliability, Southern would propose limiting the applicability through an engineering assessment to evaluate critical sites based on location, vendor susceptibility to trouble, or some other valid criterion. Southern agrees that the modifications made in PRC-002-5 are cost effective.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	

Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
The granularity of the distribution feeder level is questioned as to the need for such information and how it will be used. In order to store the data, new applications are needed which are not economical.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	No
Document Name	
Comment	
TransAlta supports the comments provided by AEP.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
The modifications proposed in new Standard PRC-028-1 are not cost effective in preventing undesirable IBR responses during Bulk Electric System faults.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the MRO NSRF and the NAGF for question #2.	
Likes 0	
Dislikes 0	
Response	

This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
The modifications made in this PRC-028-1 draft are an improvement in cost expenditures from the initial version. However, the implementation costs for PRC-028-1 are still appreciably higher than PRC-002. With the additional data requirements and higher sampling rates, the costs are higher per facility for PRC-028 than PRC-002. With DME required to be implemented at all BES IBR facilities and many non-BES IBR facilities, the overall costs of PRC-028 exceeds PRC-002. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	

Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
The level of data recording required and the amount of data that is to be collected is significantly greater than PRC-002. Also, requiring all applicable Facilities to have a DDR seems excessive. For PRC-002, the threshold for DDR is governed by a notification by the RC of applicable BES Elements however there is no comparable Requirement in PRC-028 resulting in all IBR generation being obligated to provide DDR data.	

There is a significant cost associated with the installation and maintenance of a DDR and expecting an IBR to have this level of recording when they do not meet the BES definition may be overreaching. Could this be better addressed by TOs having DDRs that could capture more information from multiple generation facilities during an event?	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

Requiring DME equipment at all IBR facilities will be excessively costly compared to the value having the equipment. It is hard to believe that every single IBR site needs to have this equipment installed.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement.

As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we s**trongly disagree** with making this new standard inclusive of all applicable IBR facilities r**egardless of risk to the BES**.

In the opinion of ACES, a blanket approach requiring every applicable IBR facility to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which IBR facilities would provide the most benefit to the BES, before selectively adding such capabilities.

In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach as is done in PRC-002-5.

Likes 0	
Dislikes 0	

Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State can not comment on cost effectiveness at this time.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
The modifications made in this PRC-028-1 draft are an improvement in cost expenditures from the initial version. However, the implementation costs for PRC-028-1 are still appreciably higher than PRC-002. With the additional data requirements and higher sampling rates, the costs are higher per facility for PRC-028 than PRC-002. With DME required to be implemented at all BES IBR facilities and many non-BES IBR facilities, the overall costs of PRC-028 exceeds PRC-002.	

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye Power supports the comments made by ACES: It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have litle to no cost to implement. As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address IBR facilities; however, we strongly disagree with making this new standard inclusive of all applicable IBR facilities regardless of risk to the BES. In the opinion of ACES, a blanket approach requiring every applicable IBR facility to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which IBR facilities would provide the most benefit to the BES, before selectively adding such capabilities. In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach as is done in PRC-002-5.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Requiring DME equipment at all IBR facilities will be excessively costly compared to the value having the equipment. It is hard to believe that every single IBR site needs to have this equipment installed.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	No
Document Name	
Comment	
Yes for new IBR facilities. For existing IBR facilities, the location requirements are reasonable; however, the required sample rates and data retention requirements may require additional investment in the collector substation.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

For the reasons expressed below, AEP is concerned by the cost versus perceived reliability benefit of the new Standard PRC-028-1.

AEP does not consider the inclusion of “at least one IBR Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% of the longest collector feeder” in PRC-028 1.2 and 1.3 as cost effective. AEP questions the reliability benefit of the data these BES Elements will provide when considering the proposed requirements of PRC-029 to a performance-based ride-through standard that ensures generators remain connected to the BPS during system disturbances and the proposed requirements of PRC-030, Unexpected Inverter-Based Resource Event Mitigation. Requirements proposed in PRC-030 clearly make the GO responsible for the performance of the Invertor-Based Resources and IBR units it owns. The proposed obligation to collect and provide FR and SER data beyond the MPT bus(es) in PRC-028 is unwarranted.

PRC-028 does not currently limit the applicability of required data, while PRC-002 provides criteria which limits the BES Elements that are required to have dynamic disturbance recording data.

AEP does not believe capturing all fault codes and fault alarms listed in R1.2 and R1.3 under this standard would be beneficial to the Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC as there are several OEMs with thousands of differing fault codes and fault alarms. AEP is concerned with the ability of these entities to understand or utilize the data in an timely manner. For some entities, this data would be more akin to SCADA quality data and not delivered with the timing nor accuracy of typical SER data. In addition, under PRC-030, we are asking the GO to resolve those issues. AEP recommends the SDT for PRC-028, PRC-029 and PRC-030 review each proposed standard obligation to ensure there is an integrated plan across these standards to achieve the goal of correcting the past performance of Invertor-Based Resources and IBR units. Having a coherent strategy document that explains how these three standards complement each other (and not be duplicative) would be beneficial.

Likes 0	
Dislikes 0	

Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	No
Document Name	
Comment	
NRG supports NAGFs comments concerning excessive cost burden for IBR facility owners.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Cannot determine cost effectiveness	
Likes 0	
Dislikes 0	
Response	

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Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	No
Document Name	
Comment	
No, simply from a value-add perspective. The standard requires IBR owners to have a robust compliance program implemented as well as event data collection process in place. However, for example, Requirement R1.2 only requires fault codes, fault alarms, mode status change, etc., from a single IBR Unit far down the feeder. This is common practice for this information to be stored on the IBR Unit inverter or logging device. This will not help any event analysis process as it will not paint an adequate picture of the IBR facility's abnormal performance, if analyzed. At a minimum, fault codes should be available from every single IBR Unit within the facility. Lack of comprehensive data has significantly affected the ERO Enterprise's ability to conduct event analysis at many facilities over the past 7 years, as reported in numerous disturbance reports. The proposed standard would lead to inadequate data available at the inverter-level to do any useful event analysis and model validation, possibly leading to ongoing inconclusive root cause analyses. This would not be cost effective for industry.	
Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Rob Robertson - Leeward Renewable Energy - 5	
Answer	No
Document Name	LRE PRC-028 April 2024 comments April 11 2024.docx
Comment	

Likes 0	
Dislikes 0	
Response	
This is a FERC Order 901 related project to address reliability gaps created by inverter based resources. With current version after the modifications made by the drafting team (from the previous version), hopefully the cost is not that significant.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
SRP believes that while implementation of these changes may be costly, they provide high value from operation, integration, and monitoring perspective.	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation agrees with the PRC-002-5 cost but inverter base does not apply to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
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	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
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.	
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.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michael Johnson - Michael Johnson On Behalf of: 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 does not have any input on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	

Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE abstains from responding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	

Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
Cannot determine cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy's focus is to assure the effective and efficient reduction of risks to the reliability and security of the grid and will not provide comments on the cost effectiveness of the proposed changes.	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

3. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is unable to support the current Implementation Plan driven by our concerns with the scope and requirements of the current draft of PRC-028.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has modified the Implementation Plan.	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Implementation Plan Says: R1-7: Current imp plan is 50% in 3 calendar years after effective date, 100% by 1/1/2030 R8: max 9 months after effective date R9: no later than 1/1/2029	

The phased in implementation plan needs to be given in a time frame after the effective date for the standard. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all IBR facilities. PRC-028, as written, will require much more DME than did PRC-002, and the implementation plan needs to recognize this difference and provide adequate time to accomplish.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	
Wendy Kalidass - U.S. Bureau of Reclamation – 5	
Answer	No
Document Name	
Comment	
Reclamation supports an 18-month implementation time frame.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	

Comment	
Buckeye Power supports the comments made by ACES: As writen, PRC-028-1 is applicable to both BES and non-BES IBRs; consequently, we recommend updating the Implementation Plan to use the term "IBR facility(ies)" in lieu of the term defined term "Facility(ies)". From the perspective of ACES, the special stipulations surrounding commercial operation are overly complex and unnecessary. For example, assume PRC-028-1 is approved by FERC and becomes effective 10/1/2024. Using the provided example, the end of the first calendar year that is 12 months following the effective date of the standard would be 12/31/2025. Thus any facilities entering commercial operation prior to 10/1/2025 would have until 12/31/2025 to be compliant while any facilities entering commercial operation on or after 10/1/2025 must be compliant immediately. We do not believe that a delay of only 1 day should move the compliance deadline forward by 3 calendar months. We recommend removing these special stipulations and instead address this specific case using a strategy akin to that used for existing facilities. We suggest the following language: "For facilities entering commercial operation a er the effective date: Entities shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of PRC-028-1."	
Likes 0	
Dislikes 0	
Response	
Thank you. See response to ACES comments.	
Kimberly Turco - Constellation – 6	
Answer	No
Document Name	
Comment	
Although the PRC-028 Implementation Plan mirrors PRC-002-2 Implementation Plan, PRC-028 requires all BES IBRs and many non-BES IBRs to have DME installed. If the GO has a large IBR fleet, numerous DME installations would be required with a demanding project schedule. With	

the large amount of DME required to be installed per PRC-028, OEMs might not be able to provide GOs with a timely supply of DME equipment.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT recognizes the possibility of supply chain issues. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan. Supply chain issues could be cited under subpart 1.3 of the extension request.

Jennifer Bray - Arizona Electric Power Cooperative, Inc. – 1

Answer	No
Document Name	

Comment

AEPC has signed on to ACES comments:

As written, PRC-028-1 is applicable to both BES and non-BES IBRs; consequently, we recommend updating the Implementation Plan to use the term “IBR facility(ies)” in lieu of the term defined term “Facility(ies)”.

From the perspective of ACES, the special stipulations surrounding commercial operation are overly complex and unnecessary. For example, assume PRC-028-1 is approved by FERC and becomes effective 10/1/2024. Using the provided example, the end of the first calendar year that is 12 months following the effective date of the standard would be 12/31/2025. Thus any facilities entering commercial operation prior to

10/1/2025 would have unθl 12/31/2025 to be compliant while any facilities entering commercial operation on or after 10/1/2025 must be compliant immediately. We do not believe that a delay of only 1 day should move the compliance deadline forward by 3 calendar months. We recommend removing these special stipulations and instead address this specific case using a strategy akin to that used for existing facilities. We suggest the following language: "For facilities entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of PRC-028-1."	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to ACES comments.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Implementation Plan Says: R1-7: Current imp plan is 50% in 3 calendar years after effective date, 100% by 1/1/2030 R8: max 9 months after effective date R9: no later than 1/1/2029 The phased in implementation plan needs to be given in a time frame after the effective date for the standard. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all IBR facilities. PRC-028, as written, will require much more DME than did PRC-002, and the implementation plan needs to recognize this difference and provide adequate time to accomplish.	

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see responses to MRO NSRF and NAGF comments.	
Alison MacKellar - Constellation – 5	
Answer	No
Document Name	
Comment	
Although the PRC-028 Implementation Plan mirrors PRC-002-2 Implementation Plan, PRC-028 requires all BES IBRs and many non-BES IBRs to have DME installed. If the GO has a large IBR fleet, numerous DME installations would be required with a demanding project schedule. With	

the large amount of DME required to be installed per PRC-028, OEMs might not be able to provide GOs with a timely supply of DME equipment. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT recognizes the possibility of supply chain issues. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan. Supply chain issues could be cited under subpart 1.3 of the extension request.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	No
Document Name	
Comment	
TransAlta recommends removing the stipulations surrounding commercial operation. There are associated project execution risks with making design changes later in a project. TransAlta would prefer to have the flexibility to install and/or configure monitoring equipment after commercial operation. Thus, TransAlta recommends updating the implementation plan to specify compliance with Requirements R1 through R7 at 50% of plants/Facilities within 3 calendar years and 100% within 6 calendar years for all plants/Facilities regardless of commercial operation date.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The current Implementation Plan has a fixed end date because FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Propose three (3) calendar years instead of one (1) year for budgeting and planning purposes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The current Implementation Plan already gives 3 years for 50% and until January 1, 2030 for 100% of IBRs in commercial operation on or before the effective date. The implementation timeline for IBRs entering commercial operation after the effective date has been revised in the latest draft.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
The Plan is too agressive. Dominion Energy recommends an additional 12-24 months to accomodate all of the non-BES IBRs that need to now be included.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	
Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The PRC-028-1 standard as written, requires 50% completion within (3) calendar years and 100% completion of R1-R7 by 1/1/2030, R9 by 1/1/2029 and R8 a maximum of 9 months after the effective date. The phased-in implementation plan needs to be given in a timeframe after the effective date for the standards. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all applicable IBR facilities. PRC-028, as written, will require much more DME than PRC-002 did, and the implementation plan needs to recognize this difference and provide adequate time to accomplish. Traditional language for implementation plans in other Standards have provided a certain period after implementation instead of a fixed date (e.g. within 6 calendar years of the effective date…).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	

Comment	
NIPSCO is not able to support the current implementation plan until concerns with the requirements of PRC-028 are addressed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	
See response to questions 4 and 5	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO NERC Standards Review Forum's (NSRF) comments.	

Likes 0	
Dislikes 0	
Response	
Thank you. See response to MRO NSRF comments.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Implementation Plan Says: R1-7: Current imp plan is 50% in 3 calendar years after effective date, 100% by 1/1/2030 R8: max 9 months after effective date R9: no later than 1/1/2029 The phased in implementation plan needs to be given in a time frame after the effective date for the standard. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all IBR facilities. PRC-028, as written, will require much more DME than did PRC-002, and the implementation plan needs to recognize this difference and provide adequate time to accomplish.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	

Marty Hostler - Northern California Power Agency – 4	
Answer	No
Document Name	
Comment	
No. Entities more need time to budget for projects and to coordinate modifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
As written, PRC-028-1 is applicable to both BES and non-BES IBRs; consequently, we recommend updating the Implementation Plan to use the term “IBR facility(ies)” in lieu of the term defined term “Facility(ies)”. From the perspective of ACES, the special stipulations surrounding commercial operation are overly complex and unnecessary. For example, assume PRC-028-1 is approved by FERC and becomes effective 10/1/2024. Using the provided example, the end of the first calendar year that is 12 months following the effective date of the standard would be 12/31/2025. Thus any facilities entering commercial operation prior to 10/1/2025 would have until 12/31/2025 to be compliant while any facilities entering commercial operation on or after 10/1/2025 must be compliant immediately. We do not believe that a delay of only 1 day should move the compliance deadline forward by 3 calendar months.	

We recommend removing these special stipulations and instead address this specific case using a strategy akin to that used for existing facilities. We suggest the following language: “For facilities entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of PRC-028-1.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT will be making overall revisions to the Technical Rationale and Implementation Plan before the next posting. The current Implementation Plan has a fixed end date because FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan. The Implementation Plan language referencing IBRs not in operation at the effective date of the standard has also been revised.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Implementation Plan Says: R1-7: Current imp plan is 50% in 3 calendar years after effective date, 100% by 1/1/2030 R8: max 9 months after effective date R9: no later than 1/1/2029	

The phased in implementation plan needs to be given in a time frame after the effective date for the standard. Specifying a fixed date may not provide adequate time for the wide scale installation of DME at all IBR facilities. PRC-028, as written, will require much more DME than did PRC-002, and the implementation plan needs to recognize this difference and provide adequate time to accomplish.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	
Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	No
Document Name	
Comment	
Entities need more time to budget for projects and to coordinate modifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	
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.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Implementation plan seems reasonable. Changes to PRC-002 are clarifying in nature, for the removal of IBRs. PRC-028 would be a new PRC with a 3 year implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	

Comment	
Implementation plan seems reasonable. Changes to PRC-002 are clarifying in nature, for the removal of IBRs. PRC-028 would be a new PRC with a 3 year implementation.	
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	
While FirstEnergy supports the Implementation Plan, we offer our comments. See our response to Q4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
We recognize that there is a cost but the benefits to relaibility are worthwhile.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Six years would be a sufficient amount of time to plan and budget for the procurement and installation of the DDR equipment barring any supply chain risk complications or any other delays. USV recognizes the FERC directive mandating completion by 1/1/2030, however, due to	

many of the IBR sites having strict language when dealing with manufacturers warranty and having to rely on third parties, it may result in additional complications that could delay the installation and setting up of this highly specialized equipment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comment. The SDT recognizes the potential for supply chain or other constraints, thus the inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan.	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the NAGF for question #3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. See responses to EEI and NAGF comments.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. See reply to EEI comments.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. See reply to EEI comments.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
EEI supports proposed implementation plan as developed for PRC-002 and PRC-028.	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Michael Johnson - Michael Johnson On Behalf of: 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	
{C}PG&E supports the proposed implementation plan as developed for PRC-002 and PRC-028.	
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 the EEI for this question.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support. See response to EEI comments.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
None.	
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 proposed implementation plan as developed for PRC-002 and PRC-028.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Implementation plan seems reasonable. Changes to PRC-002 are clarifying in nature, for the removal of IBRs. PRC-028 would be a new PRC with a 3 year implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
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.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
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.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 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.	
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.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Patricia Ireland - DTE Energy - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Colin Chilcoat - Invenergy LLC - 5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Rhonda Jones - Invenergy LLC - 5,6	
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	
Document Name	
Comment	
Tri-State agrees with MRO Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. See response to MRO comments.	

4. Do you agree with introduction of Requirement R9 in PRC-028-1 requiring Entities of an applicable facility that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance to develop, maintain, and implement a Corrective Action Plan?

Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	

Invenergy **suggests the below language** for R9:

R9. Each Generator Owner and Transmission Owner with a documented equipment limitation that would prevent an applicable IBR that is in commercial operation prior to the effective date of this standard from installing disturbance monitoring equipment in accordance with Requirements R1 through R7 shall communicate each equipment limitation to the Regional Entity.

9.1. Each Generator Owner and Transmission Owner shall include in its documentation:

- 9.1.1. Identifying information of the applicable Element and cause of the limitation
- 9.1.2. Which aspect(s) of disturbance monitoring the Element would be unable to meet

9.2. Each Generator Owner and Transmission with a previously communicated equipment limitation that repairs or replaces the equipment causing the limitation shall document and communicate such equipment change to the Regional Entity within 30 days of the equipment change.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The intent of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline. It was not meant to provide technical feasibility exceptions such as in this suggested revision. FERC Order 901 requires disturbance monitoring data from the IBRs identified in the Applicability section of PRC-028.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF does not support the proposed Requirement R9 due to the potential cost issues for existing IBR facilities as well as the potential reliability impacts due to existing IBR facilities ceasing operation due to economics.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. R9 did not add any financial burden to the responsible entity. The purpose of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline.	

Colin Chilcoat - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
Invenergy suggests the below language for R9: **R9.** Each Generator Owner and Transmission Owner with a documented equipment limitation that would prevent an applicable IBR that is in commercial operation prior to the effective date of this standard from installing disturbance monitoring equipment in accordance with Requirements R1 through R7 shall communicate each equipment limitation to the Regional Entity.	

9.1. Each Generator Owner and Transmission Owner shall include in its documentation:

9.1.1. Identifying information of the applicable Element and cause of the limitation

9.1.2. Which aspect(s) of disturbance monitoring the Element would be unable to meet

9.2. Each Generator Owner and Transmission with a previously communicated equipment limitation that repairs or replaces the equipment causing the limitation shall document and communicate such equipment change to the Regional Entity within 30 days of the equipment change.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The intent of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline. It was not meant to provide technical feasibility exceptions such as in this suggested revision. FERC Order 901 requires disturbance monitoring data from the IBRs identified in the Applicability section of PRC-028.

Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano

Answer	No
Document Name	

Comment

If the allegation that existing IBR's are causing issues then the requirements should be the same.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The requirements for new and existing IBRs are the same, but the SDT recognizes that retrofitting existing equipment can be more difficult than including the DME as part of a capital project. R9 did not allow for ongoing exceptions. The intent of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline.	
Patricia Ireland - DTE Energy - 4	
Answer	No
Document Name	
Comment	
The idea of allowing a corrective action plan for compliance challenges at existing operations is a good one however the circumstance that would allow for use of the CAP is poorly defined. What exactly is "not able to install" ? Does that mean within reason? cost effectively? Not able to install regardless of time or money is a very high bar and essentially unhelpful.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The process for seeking an extension has been heavily revised and moved to the Implementation Plan for the next draft. These extensions will have to be approved by the Regional Entity.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC is concerned that the requirement as written may be overly broad. To address this, examples of legitimate reasons that an entity may be unable to “install disturbance monitoring equipment” should be provided in the Technical Rationale.	

Alternatively, this concern could be addressed by revising the standard to require all installations to be completed within the parameters of the Implementation Plan for PRC-028.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The process for seeking an extension has been heavily revised and moved to the Implementation Plan for the next draft. These extensions will have to be approved by the Regional Entity. The SDT intends to try to expand on how it should be used in the PRC-028 Technical Rationale.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Requiring comprehensive DME for SER, FR, and DDR at all "old" facilities is unnecessary. The investigations performed into past grid disturbances have documented the trouble that legacy facilities have been experiencing. Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability. R2.3 and R3.3 and their subparts are unnecessary as these devices have not been identified as causing any problems that suggest they need to be monitored.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. This SDT has been tasked with not only making sure data is available to analyze IBR response to BES disturbances, but also, with the added directives of FERC Order 901, ensuring disturbance data is available to evaluate IBR performance and validate IBR models. That expanded scope makes monitoring at all IBRs important. Individual unit requirements have been removed from the latest draft.	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
No. If the allegation that existing IBR's are causing issues then the requirements should be the same.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The requirements for new and existing IBRs are the same, but the SDT recognizes that retrofitting existing equipment can be more difficult than including the DME as part of a capital project. R9 did not allow for ongoing exceptions. The intent of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Requiring comprehensive DME for SER, FR, and DDR at all "old" facilities is unnecessary. The investigations performed into past grid disturbances have documented the trouble that legacy facilities have been experiencing. Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability. R2.3 and R3.3 and their subparts are unnecessary as these devices have not been identified as causing any problems that suggest they need to be monitored.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. This SDT has been tasked with not only making sure data is available to analyze IBR response to BES disturbances, but also, with the added directives of FERC Order 901, ensuring disturbance data is available to evaluate IBR performance and validate IBR models. That expanded scope makes monitoring at all IBRs important. Individual unit requirements have been removed from the latest draft.	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the comments submitted by NAGF. Capital Power does not support the proposed Requirement R9 due to the potential cost issues for existing IBR facilities. This can be a costly endeavor if equipment was recently replaced as per planned life cycle replacement strategies. There is also the potential reliability impacts due to existing IBR facilities ceasing operation due to economics.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. R9 did not add any financial burden to the responsible entity. The purpose of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline.	
Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk	
Answer	No
Document Name	

Comment	
Minnesota Power supports MRO NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. See the response to MRO NSRF comments.	
Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	
Comment	
PG&E does not agree with the language proposed. PG&E agrees with the following EEI comments: 1 - Given the voltage level identified in the Applicability section of PRC-028, DPs will likely own applicable equipment that will be impacted. For this reason, we suggest that DPs be added to R9. 2 - The use of "applicable facility" in R9 should be removed because this term has no defined meaning. To resolve this issue, we suggest replacing "of an applicable facility" with "that own equipment as identified in "Section 4.2 (Facilities)". 3 - Disturbance Monitoring Equipment is a NERC defined term and should be capitalized to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. See the response to EEI comments. 1 – The language used in the Applicability section of the next draft has been revised and will not include the non-BES IBRs affected by the Rules of Procedure revision process. 2 – The SDT will review the standard for use of “facility”. The NERC standard template uses “Facilities” under the “Applicability” section, and the SDT intended the phrase “applicable facilities” to refer back to that section. However, the SDT recognizes that this can cause confusion when “Facilities” is also a NERC Glossary term. 3 – The SDT intends to review all documents for NERC Glossary terms and associated capitalization. Thank you for noting this one.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	
Conceptually, no, WECC believes there should not be a compliance loophole built into a Reliability Standard. General considerations mention three (3) calendar years to accommodate normal outage schedules. As written the entity may only have to outage one (1) IBR unit per collector feeder (and in some cases maybe only (1) IBR Unit for the entire Inverter-Based Resource), to install equipment in Parts 1.2/2.2. (as an example as it is not clear where that data is being recorded). Granted, SER/FR on circuit breakers, if not already installed at Part 1.1 locations require a complete outage but is it not already industry standard to have that capability on breakers in that voltage class? Waiting until 2029 to create a CAP per the Implementation Plan does not support reliable operations (and at least two “normal outage schedule” periods will have passed since the official start of this Project to accommodate the SER/FR additions if not present.) Part 9.2 allows too broad of a scope to be considered reliable with no support (what is “beyond the control” and who defines that?). Submitting the CAP to the Regional Entity with a request to extend time provided for compliance does not support reliability. The Regional Entity does not necessarily have the authority to grant extensions for compliance. Timelines for compliance are dictated by Implementation Plans or the Requirement language itself. There are no required timelines for the CAP which could equate to a CAP that is never implemented. WECC appreciates the idea of striking a balance between cost and reliability (with compliance impacts) but as written the reliability aspect will suffer to support being compliant.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. In the next draft, the process for seeking an extension has been heavily revised and moved to the Implementation Plan. The SDT intends to look at clarifying when and how it should be used in the PRC-028 Technical Rationale.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
Section R3.2 seems to specify that a Schweitzer level sampling rate of 64 samples per cycle needs to be implemented which it does not appear to be within the capabilities of the event recording generated by the turbine controllers. The minimum requirements appear to be the AC and Frequency values at that high of a resolution. The GE documentation suggest the points and sampling rate of the trip files generated vary. Even if the resolution we need is possible, it may not have the correct setting dependent on the event that is recorded in the trip file. The fastest sampling rate in the GE trending software is at a 10 milli-seconds, which is significantly less than what would be required for 64 samples per 1 hz.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Unit level monitoring has been removed from the latest draft of the standard.	
Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
R9.5 requires Entities submit the CAP to the Regional Entity. Entities will require guidance on the process with input from each Regional Entity. This is an administrative process that could cause undue delay in the CAP process while managing time constraints. It would be more	

efficient for the Entity to create and maintain its own CAP similar to PRC-026 R3 and R4. The CAP can be made available during periodic audits. There is no demonstration of how “reporting” CAPs to Regional Entities adds to system Reliability.

Requiring comprehensive DME for SER, FR, and DDR at all existing facilities is unnecessary. The investigations performed for past grid disturbances have documented the trouble that legacy facilities have been experiencing. Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability. R2.3 and R3.3 and their subparts are not necessary as these devices have not been identified as causing any problems that suggest they need to be monitored.

Southern Company agrees with EEI suggested modifications to the text:

1. The use of “applicable facility” in R9 should be removed because this term has no defined meaning. To resolve this issue, it is suggested replacing “of an applicable facility” with “that own equipment as identified in Section 4.2 (Facilities)”.

2. Disturbance Monitoring Equipment is a NERC defined term and should be capitalized in order to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

Requests for extension must be approved by the Regional Entity, so they would not be valid without being filed.

This SDT has been tasked with not only making sure data is available to analyze IBR response to BES disturbances, but also, with the added directives of FERC Order 901, ensuring disturbance data is available to evaluate IBR performance and validate IBR models. That expanded scope makes monitoring at all IBRs important. Individual unit requirements have been removed from the latest draft.

Please, also see response to EEI comments.

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), the MRO NSRF, and the NAGF for question #4.	
Likes 0	
Dislikes 0	
Response	
Thank you. See responses to EEI, MRO NSRF, and NAGF comments.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you. See responses to MRO NSRF and NAGF comments.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	

Comment	
Requiring comprehensive DME for SER, FR, and DDR at all "old" facilities is unnecessary. The investigations performed into past grid disturbances have documented the trouble that legacy facilities have been experiencing. Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability. R2.3 and R3.3 and their subparts are unnecessary as these devices have not been identified as causing any problems that suggest they need to be monitored.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Thank you for your comments. This SDT has been tasked with not only making sure data is available to analyze IBR response to BES disturbances, but also, with the added directives of FERC Order 901, ensuring disturbance data is available to evaluate IBR performance and validate IBR models. That expanded scope makes monitoring at all IBRs important. Individual unit requirements have been removed from the latest draft.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State agrees with MRO Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to MRO comments.	

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	

Black Hills Corporation agrees with NAGF comments. The NAGF does not support the proposed Requirement R9 due to the potential cost issues for existing IBR facilities as well as the potential reliability impacts due to existing IBR facilities ceasing operation due to economics.

Black Hills Corporation also agrees with this comment from EEI: EEI supports the language proposed in Requirement R9 but offers the following non substantive comments for consideration:

1. The use of “applicable facility” in R9 should be removed because this term has no defined meaning. To resolve this issue, we suggest replacing “of an applicable facility” with “that own equipment as identified in “Section 4.2 (Facilities)”.

2. Disturbance Monitoring Equipment is a NERC defined term and should be capitalized in order to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.

Likes 0	
Dislikes 0	
Response	
Thank you. Please see responses to NAGF and EEI comments.	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

Requiring comprehensive DME for SER, FR, and DDR at all "old" facilities is unnecessary. The investigations performed into past grid disturbances have documented the trouble that legacy facilities have been experiencing. Focusing on new equipment that has been designed and built to better ride-thru system disturbances will provide more benefit and value to system reliability. R2.3 and R3.3 and their subparts are necessary as these devices have not been identified as causing any problems that suggest they need to be monitored	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. This SDT has been tasked with not only making sure data is available to analyze IBR response to BES disturbances, but also, with the added directives of FERC Order 901, ensuring disturbance data is available to evaluate IBR performance and validate IBR models. That expanded scope makes monitoring at all IBRs important. Individual unit requirements have been removed from the latest draft.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE asks DT to consider removing R9 and putting it into implementation plan to avoid future administrative burden to retire R9 when all CAPs are complete or consider R9 to mirror PRC-028 R8 or PRC-002 R12 to ease admistrative burden.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. In the next draft, the process for seeking an extension has been heavily revised and moved to the Implementation Plan.	

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	No
Document Name	
Comment	
NRG is in alignment with NAGFs comments regarding Requirement 9 due to potential cost issues and reliability impacts for existing IBR facilites to install this equipment.	
Likes 0	
Dislikes 0	
Response	
Thank you. See response to NAGF comments.	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports and recommends implementation of EEI provided comments. Additionally, PRC-028-1 R9 that reads: Each Transmission Owner and Generator Owner of an applicable facility as specified in section A.4.2 that is "in commercial operation before the effective date of this standard" that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance shall develop, maintain, and implement a Corrective Action Plan to provide the required capability. For the sake of fully defining compliance expectations, please amend language to define what action, if any, TO/GO entities must take if it is "not in commercial operation before the effective date of this standard".	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. See the response to EEI comments. R9 only applied to entities specified in R9. All others should reference the Implementation Plan. In the next draft, the process for seeking an extension previously defined by R9 has been heavily revised and moved to the Implementation Plan.	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	No
Document Name	
Comment	
No. This appears to be redundant with the development of an effective and reasonable implementation plan for this standard. The proposed implementation plan for 5+ years to get compliant with the standard seems sufficient to install/enable disturbance monitoring equipment. Elevate is not aware of any supply chain or other issues that would cause such long delays (as opposed to high power equipment, controllers, hardware, etc.).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Wording should be clarified where “applicable facility” is used as this is not a defined term.	
Likes 0	

Dislikes 0	
Response	
Thank you for your support and comment. The SDT will review the standard for use of “facility”. The NERC standard template uses “Facilities” under the “Applicability” section, and the SDT intended the phrase “applicable facilities” to refer back to that section. However, the SDT recognizes that this can cause confusion when “Facilities” is also a NERC Glossary term.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the language proposed in Requirement R9 but offers the following non substantive comments for consideration: 1. The use of “applicable facility” in R9 should be removed because this term has no defined meaning. To resolve this issue, we suggest replacing “of an applicable facility” with “that own equipment as identified in “Section 4.2 (Facilities)”. 2. Disturbance Monitoring Equipment is a NERC defined term and should be capitalized in order to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. 1. The SDT will review the standard for use of “facility”. The NERC standard template uses “Facilities” under the “Applicability” section, and the SDT intended the phrase “applicable facilities” to refer back to that section. However, the SDT recognizes that this can cause confusion when “Facilities” is also a NERC Glossary term. 2. The SDT intends to review all documents for NERC Glossary terms and associated capitalization. Thank you for noting this one.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
None.	
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 the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you. See response to EEI comments.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
EEI supports the language proposed in Requirement R9 but offers the following non substantive comments for consideration:	

{C}1. {C}The use of “applicable facility” in R9 should be removed because this term has no defined meaning. To resolve this issue, we suggest replacing “of an applicable facility” with “that own equipment as identified in “Section 4.2 (Facilities)”.

{C}2. {C}Disturbance Monitoring Equipment is a NERC defined term and should be capitalized in order to ensure that responsible entities understand the scope of their responsibilities under this Reliability Standard.

Likes 0	
Dislikes 0	

Response

Thank you for your support and comments.

1. The SDT will review the standard for use of “facility”. The NERC standard template uses “Facilities” under the “Applicability” section, and the SDT intended the phrase “applicable facilities” to refer back to that section. However, the SDT recognizes that this can cause confusion when “Facilities” is also a NERC Glossary term.
2. The SDT intends to review all documents for NERC Glossary terms and associated capitalization. Thank you for noting this one.

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	

Comment

SIGE supports the inclusion of Requirement R9; however, SIGE requests a clarification regarding disturbance monitoring equipment referenced in Requirement R9. Was the Standard Drafting team’s use of the phrase “disturbance monitoring equipment” intended to reference the equipment covered by the NERC defined term “Disturbance Monitoring Equipment”? If so, SIGE recommends capitalizing the proposed language to clarify the intent.

Additionally, SIGE recommends two revisions to R9: 1) revise R9 to mirror the language in section 4.2 Functional Entities and 2) align the Applicability section reference with other NERC Standards. Recommended revisions are shown below:

R9. Each Transmission Owner and Generator Owner ***that owns equipment as identified*** in ***Applicability*** section ***4.2*** that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with

Requirements R1 through R7 in the time provided for compliance shall develop, maintain, and implement a Corrective Action Plan to provide the required capability. For each Corrective Action Plan, the Transmission Owner and Generator Owner shall:	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. The SDT intends to review all documents for NERC Glossary terms and associated capitalization. Disturbance Monitoring Equipment was intended to refer to the NERC Glossary term. In the next draft, the process for seeking an extension has been heavily revised and moved to the Implementation Plan.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. See the response to EEI comments.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. See the response to EEI comments.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes. CEHE supports Southern Indiana Gas & Electric, Company comments submitted for question 4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. See response to Southern Indiana Gas & Electric, Company comments.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
If the standard and implementation plan were to pass in its current form, we do not feel that 2030 would be a sufficient amount of time to implement DDR recording at all sites that meet the applicability section of PRC-028. The procurement and installation process is time-consuming due to the limited amount of vendors and having to do additional efforts for supply chain risk, etc.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT recognizes the possibility of supply chain issues. FERC Order 901 requires that PRC-028 be effective and enforceable no later than January 1, 2030. This SDT has no option to extend that deadline. The concession provided to industry is inclusion of a process allowing the GO or TO to request an extension through its Regional Entity for IBRs in commercial operation before the effective date of PRC-028-1. This was R9 in the previous draft but has been moved to the Implementation Plan. Supply chain issues could be cited under subpart 1.3 of the extension request.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	

SRP agrees with industry that while these changes provide value in evaluating facilities when there are disturbances, however it is also critical to assign responsibility to IBR facilities and their owners to enforce these requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Wording should be clarified where “applicable facility” is used as this is not a defined term.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comment. The SDT will review the standard for use of “facility”. The NERC standard template uses “Facilities” under the “Applicability” section, and the SDT intended the phrase “applicable facilities” to refer back to that section. However, the SDT recognizes that this can cause confusion when “Facilities” is also a NERC Glossary term.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Wording should be clarified where “applicable facility” is used as this is not a defined term.	
Likes 0	
Dislikes 0	

Response	
Thank you for your support and comment. The SDT will review the standard for use of “facility”. The NERC standard template uses “Facilities” under the “Applicability” section, and the SDT intended the phrase “applicable facilities” to refer back to that section. However, the SDT recognizes that this can cause confusion when “Facilities” is also a NERC Glossary term.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 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.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 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.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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.	
Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
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.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
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.	
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.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Not applicable to Reclamation.	
Likes 0	

Dislikes 0	
Response	
Thank you for responding.	

5. Provide any additional comments for the standard drafting team to consider, if desired.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
1) In 4.3.2 of PRC-002-5, we need to clarify this trigger condition “Phase undervoltage or overcurrent”. Does “phase undervoltage” refer to phase-phase or phase-to-neutral undervoltage”? 2) Under “Facilities” of 4.1 in PRC-028-1, how was this 60 kV threshold determined? 3) In section 3.1.3.2, section 3.2.3.1 and section 3.3.3.2 of PRC-028-1, we need to clarify this trigger condition “AC phase overvoltage and undervoltage”. Does “phase undervoltage” refer to phase-phase or phase-to-neutral undervoltage”? 4) In R8 of PRC-028-1, “Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.” should probably read “Submit a Corrective Action Plan (CAP) and a CAP implementing schedule to the Regional Entity”?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1) The SDT leaves this decision to engineering judgment 2) This threshold came directly from the latest NERC ROP GO/GOP registration criteria which were approved by the NERC Board in February and filed with FERC on March 19, 2024. However, the language used in the Applicability section of the next draft has been revised. It will not include the non-BES IBRs affected by the Rules of Procedure revision process. 3) The SDT leaves this decision to engineering judgment	

4) R8 has been revised in the next draft for clarity.	
Ryan Quint - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable, Group Name Elevate Energy Consulting	
Answer	
Document Name	
Comment	
It is unclear why NERC is so adamant about not adopting IEEE standards within the NERC standards, and has stated this in multiple forums related to the adoption of IEEE 2800-2022. However, then now proposes to adopt IEEE C37.111 COMTRADE standard within the new PRC-028-1 proposed standard. Inconsistency regarding NERC's approach and opinion in this area leaves industry confused, uncertain, and concerned regarding whether NERC has a clear and effective standards improvement strategy.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Requiring FR & DDR data in IEEE C37.111 COMTRADE format is consistent with PRC-002 data formatting requirements and ensures that all parties can access necessary files when FR and DDR files are shared.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy supports and recommends implementation of EEI provided comments.	
Likes 0	
Dislikes 0	
Response	

Thank you. Please see response to EEI comments.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
Overall wording for the sections mentioned above for PRC-028 should be cleaned up. Terms like IBR should have formal definitions, outside of PRC-028 in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Applicability section has been edited and reformatted for clarity in the next draft, and the language used will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	
Overall wording for the sections mentioned above for PRC-028 should be cleaned up. Terms like IBR should have formal definitions, outside of PRC-028 in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The Applicability section has been edited and reformatted for clarity in the next draft, and the language used will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro appreciates the drafting team efforts and the opportunity to comment. PRC-028-1 R1 requires an entity to record data "when triggered by ride-through operation". BC Hydro requests that drafting provides additional clarity on or criteria to determine what would constitute "ride-through operation" as it pertains to an applicable entity's compliance obligation to identify all events in scope of R1 Part 1.2. Requirement R3 Footnote 3 on "main power transformer" should use IBR instead of the undefined term "dispersed power producing resources". BC Hydro suggests that instead of this wording, which is indeed referenced in the inclusion I4 of the BES definition, the new IBR Glossary Term is preferrable. Requirement R7 requires that all SER, DDR and FR data be provided upon request by an applicable entity. BC Hydro suggests that all data may not be feasible or even required and recommends instead that the provision of the SER, DDR and FR data be done in accordance with a qualified request and within the bounds set by Part 7.1 through Part 7.5 of Requirement R7. PRC-028-1 Requirement R8 and PRC-002-5 R12 second bullet as written requires that a CAP will need to be implemented within 90 days. The VSL Table and the Technical Rationale provide clarity that it is only the CAP that requires submission within 90 days for the situations where an entity is unable to restore capability within 90 days. BC Hydro recommends that the drafting team revises the PRC-028-1 R8 and PRC-002-5 R12 wording to clarify that the 90-day timeline is only mandated for the CAP submission. Also important to clarify within the language of the Requirement is whether the 90-day timeline is based on business or calendar days. BC Hydro recommends that the implementation plan for PRC-028-1 be coordinated with the approval of the approval of the IBR and IBR Unit definitions.	
Likes 0	

Dislikes 0	
Response	
These requirements at the unit level have been removed from the latest draft. This footnote has been revised. Requirement R7 is bounded by subparts 7.1 through 7.6 as the requirement states "in accordance with…" PRC-028-1 Requirement R8 and PRC-002-5 R12 have been revised for clarity. Due to the time constraints of FERC Order 901, development of PRC-028 cannot be put on hold until the IBR related glossary terms are finalized. However, the language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG is supportive of NAGFs comments that the Project needs to be closely coordinated with other active NERC IBR related projects to avoid conflicts and duplication of requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The PRC-028, PRC-029, & PRC-030 and their NERC facilitators are in close contact. See response to NAGF comments.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	

Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
This comment applies to PRC-028-1 R5.2. Idaho Power presently requires existing and future IBRs connecting to its transmission system to provide plant-level PMU data. This data is streamed to a central data concentrator in real time, where it is then stored in a central data historian. The message rate has been chosen to be 30 samples per second due to limitations of the communications systems. Moving this existing system to 60 samples per cycle to obtain this data may result in significant re-design and additional costs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT addresses the need for the 60 samples per second output recording rate in the Technical Rationale.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	

Document Name	
Comment	
AZPS has no additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP has concerns with several of the requirement differences between PRC-002 and PRC-028 such as ten day data retention vs. twenty day data retention, output recording rate of electrical quantities of at least 30 times per second versus 60 times per second, synchronized clock accuracy within +/- 2 milliseconds versus +/- 1 millisecond, etc.. The Technical Rational document is silent on the reason for these differences. These changes are not insignificant, and having differing requirements for synchronous vs IBR technologies, introduces a risk for human performance error. PRC-002 Attachment 1 limits the BES buses required to record SER and FR data. During the recent system disturbance events, were any IBR facility buses required to capture SER and FR data under PRC-002? What is the reliability-driven rationale behind requiring *all* IBR facility buses to capture SER and FR data in PRC-028 as opposed to a targeted set based on an engineering analysis as done for PRC-002? PRC-002 and PRC-028 should both be revised to make it clear that the ability to provide data in CSV format is for DDR or PMU data *only.*	
Likes 0	
Dislikes 0	

Response
Thank you for your comments. It has been unusual for IBR buses (as defined in PRC-002) to meet the top 10% calculation criteria in PRC-002 Attachment 1, particularly since the Attachment 1 criteria only pertain to Transmission Owners, but some were required to be monitored under PRC-002. This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared. Please refer to the PRC-028 Technical Rationale for more details. The requirements are discussed there. The SDT has made this revision regarding data formatting in the next draft.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment

Texas RE has the following additional comments:

- Texas RE suggests removing the terms “machine based” from PRC-002-5 Requirement Part 5.1.1 as simply stating “Synchronous generating resource” is sufficient.
- In PRC-028-1 Standard, Requirement Part 2.1.3 should specify Real and reactive power on a three-phase basis*:*
    - 2.1.3. Real and reactive power on a **three-phase basis.**
- In PRC-028-1 Standard, Requirement Part 2.3.3 should remove ‘Real’ from the requirement and specify the reactive power on a three-phase basis:
    - **2.3.3. Real and Reactive power on three-phase basis.**
- Remove the ending parathesis in Requirement Part 3.2.2.
- Texas RE recommends the SDT consider specifying the trigger settings for ‘overfrequency and underfrequency’ levels to be consistent with the PRC-024 requirements:

- **3.2.3.2 Overfrequency level at minimum 60.6 Hz and underfrequency level at 59.4 Hz**
- Texas RE recommends the SDT consider including an option for existing registered entities that have IBR units that are incapable of recording data to provide technical justification for the IBR unit's inability to record based on OEM specifications or based on an independent engineering assessment.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

- This SDT didn't touch any of the data requirements in the PRC-002 standard.
- The SDT has made this revision.
- This is now R 2.2.3, and the SDT has made the suggested revision.
- This requirement has been removed
- This requirement has been removed
- FERC Order 901 requires that disturbance data is not only available to analyze IBR response to BES disturbances, but also to evaluate IBR performance and validate IBR models. That directive does not leave room for exceptions. Individual unit requirements have also been removed from the latest draft.

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	
Document Name	

Comment

Section 1.2 and 1.3: While IBR settings are important when analyzing events, the various settings and modes may not be recorded by the inverter data recorder. At a minimum 1.3.3 and 1.3.4 should be removed for IBR units that are in commercial operation since they would have not been designed to meet the requirement.

Section 2.1.3: PRC-002 does not require real and reactive power for FR data, the same should apply for PRC-028, Most fault recording equipment does not record power or frequency in FR records, this is a calculated value and is recorded in DDR/Continuous data. Software can be used to calculate power using FR data, power and frequency would not be in the comtrade file.

Section 2.3.3: Same comment as 2.1.3

Section 3.2..2 Existing IBRs may not be able to store 2 second event records at a 64 samples/cycle.

Section 3.2.3.2 Frequency triggers should not be required for FR data. They can be difficult to set and trigger erroneous events which can fill up storage. Frequency triggers should only be required for continuous/DDR recording.

Section 5.2 Not all existing install equipment may be able to meet the 60 samples/second recording rate. Requirement in PRC-002 is 30 samples/second.

Section 7.1 Existing IBRs may not be able to store FR or DDR data for 30 days.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

All individual unit requirements have been removed from the latest draft.

This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared. Also, the requirement is to have data sufficient to determine the quantities, so calculated versus recorded is acceptable.

All individual unit requirements have been removed from the latest draft.

All individual unit requirements have been removed from the latest draft.

Please see PRC-028 Technical Rationale for justification of this recording rate and above response for why PRC-028 requirements cannot be directly compared to PRC-002.

All individual unit requirements have been removed from the latest draft, and the 20 day requirement should be less of an issue with equipment used to monitor at the plant level.

Ben Hammer - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	

For R8, it is not clear whether the CAP implementation referenced in the 2nd bullet item must be complete at the end of the 90 days specified in the R8 text.   If so, what then is the difference in the first bullet (restoring the capability) and why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit?

In R9.5 does the request to extend the time provided refer to any changes made to an original CAP timeline? (there are no other deadlines for completing any R9 CAP)

In R1.2 and R1.3 remove the unneeded brackets [ ] surrounding “the effective date of this standard”.

CAPS documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment will accomplish the intent of R8 & R9.   An audit can check to ensure that all broken equipment was handled properly.

What dictates a “ride-thru” event in R1?   The IBR mode status?

Why is R2.2.1 needed to be the IBR Unit transformer HV side versus the LV side?

Comments on cost:

Based on research for the last ballot on the costs of having this on each feeder at a wind farm. This doesn't include solar IBRS.

In addition, the contributing entity estimates that the cost of installing DFR equipment on the high side of a pad mounted transformer at the base of a wind turbine in the last 10% of an existing wind turbine feeder will be $300-450k or 2-3 times the cost of installing the same equipment in an existing substation. For example, one wind farm has 14 feeders so installing this equipment on every feeder there would cost an estimated $4.2-6.3 million dollars for that one facility. EIA data shows that there are currently 604 wind farms with a size of 75 MW or greater with a total 975549 MW capacity. Assuming there is a feeder for every 10-20 MW worth of wind turbines and the estimate per installation, the range between $1.463-$2.195 billion dollars just to install these at the end of every feeder and does not include the substation installations that would be required. This estimate is only for feeders at wind turbines and does not include any estimates for solar farms or other IBRs so the total cost.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. R8 has been revised for clarity, and the same revisions have been applied to PRC-002-5, R12. In the next draft, the process for seeking an extension has been heavily revised and moved from R9 to the Implementation Plan. These brackets are part of the NERC standard development process. Once the standard is approved by FERC, the phrase “the effective date of this standard” is replaced by the actual effective date of the standard. R9 did not deal with faulty equipment. The intent of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline. Requests for extension must be approved by the Regional Entity, so they would not be valid without being filed. All individual unit requirements have been deleted from the latest draft.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	

Document Name	
Comment	

Reclamation does not agree with the modifications to the wording of BES Elements in R6 and R7 in the "Violation Severity Levels" section. 'Element' is sufficiently defined in the NERC Glossary of terms and 'BES Element' encompasses the required equipment (elements) for Disturbance Monitoring. Reclamation recommends keeping the original wording "for all applicable BES Elements".

Reclamation concurs that all IBR resources should have and maintain their own separate standards.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The revision was necessary, because some of the circuit breakers in the monitoring requirements are not BES Elements, specifically the collector circuit breakers.

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	
Document Name	
Comment	

Buckeye Power supports the comments made by ACES:

It is unclear as to what constitutes a "ride-through operation" of an IBR Unit in R1.2 and R1.3. Is this intended to be a reference to "no trip zone" identified in PRC-024? If so, as PRC-024 is not currently applicable to non-BES IBRs, how is this iden fied for those facilities? We believe additional guidance is needed for these requirements.

Likes 0	

Dislikes 0	
Response	
Thank you for your comments. Please see the response to ACES comments. Requirements 1.2 and 1.3 have been deleted from the latest draft of the standard.	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
The cost and burden of the proposed PRC-028 requirements are not believed justified by the reliability benefits it would provide. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with comments from NAGF and EEI, included here:	

The NAGF notes that Project 2021-04 needs to be closely coordinated with other active NERC IBR related projects to ensure there is no conflict and/or duplication of efforts. The NAGF recommends that NERC publish a guideline/roadmap to demonstrate how all the on-going and pending IBR work activities fit together so that industry can understand how these efforts will enhance BPS/BES reliability. For example, why is it necessary for PRC-028 to be effective prior to other new IBR standards (i.e., PRC-029/PRC-030/PRC-031)?

EEI offers the following additional comments:

DDR Requirements for PRC-002 & PRC-028

EEI suggests that consideration should be given to modifying the requirements for dynamic Disturbance recording (DDR) equipment in both PRC-002 and PRC-028 in order to permit responsible entities to either install DDR equipment or Phasor Measurement Units (PMUs) since PMU equipment capture disturbance data at equal or better rates, and have the added benefit of synchronizing disturbance data from other locations utilizing existing network communications.

Data Retention Requirements for PRC-002 & PRC-028

EEI does not agree that the data retention requirements for PRC-002 (see Requirement R11 - 10 days) and PRC-028 (Requirement R7 – 20 days) should be different. Having two different data retention requirements for two Reliability Standards that have the exact same purpose is unjustified. Given the currently enforceable version of PRC-002 has a 10 day retention period, PRC-028 should have the same data retention period.

Reliability Coordinator Responsibilities for PRC-028

EEI suggests that the RC should be provided with oversight responsibilities for the placement of DDR equipment, even at IBR facilities. While EEI understands that the desire is to have DDR equipment at all IBR Facilities, as more of these facilities are added to the BPS, it is likely that there will be clusters of IBR facilities in some areas diminishing the need for this equipment at all of these facilities. We further note that the cost of this equipment is significant, and consideration should be given to the actual need and the RC would be the best judge to make this determination.

Likes 0	
Dislikes 0	
Response	

Thank you. Please see the responses to NAGF and EEI comments.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC thanks you for the opportunity to comment and has signed on to ACES comments. It is unclear as to what constitutes a “ride-through operation” of an IBR Unit in R1.2 and R1.3. Is this intended to be a reference to “no trip zone” identified in PRC-024? If so, as PRC- 024 is not currently applicable to non-BES IBRs, how is this identified for those facilities? We believe additional guidance is needed for these requirements.	
Likes 0	

Dislikes 0	
Response	
Thank you. Please see the response to ACES comments.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	

For R8, it is not clear whether the CAP implementation referenced in the 2nd bullet item must be complete at the end of the 90 days specified in the R8 text. If so, what then is the difference in the first bullet (restoring the capability) and why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit?

In R9.5 does the request to extend the time provided refer to any changes made to an original CAP timeline? (there are no other deadlines for completing any R9 CAP)

In R1.2 and R1.3 remove the unneeded brackets [ ] surrounding “the effective date of this standard”.

CAPS documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment will accomplish the intent of R8 & R9. An audit can check to ensure that all broken equipment was handled properly.

What dictates a “ride-thru” event in R1? The IBR mode status?

Why is R2.2.1 needed to be the IBR Unit transformer HV side versus the LV side?

Based on research for the last ballot on the costs of having this on each feeder at a wind farm. This doesn't include solar IBRS. MRO NSRF estimates that the cost of installing DFR equipment on the high side of a pad mounted transformer at the base of a wind turbine in the last 10% of an existing wind turbine feeder will be $300-450k or 2-3 times the cost of installing the same equipment in an existing substation.

It is not understood what drives the 2 seconds length and the 64 samples/sec recording requirements. Existing FR equipment typically has a maximum recording time of 60 cycles and maximum of 16 or 32 samples/sec. Both of these are not consistent with similar requirements of PRC-002 (30 cycles & 16 samples/sec).

3.2 will be difficult to achieve for older IBRs. FR recording equipment will need to be added to meet this requirement. Meeting these requirements at the inverter/controller level will be challenging.

MRO NSRF recommends that the SDT reach out to various manufacturers to confirm the equipment capability and if any changes/updates that may be necessary for equipment can meet this requirement will become available.

MRO NSRF recommends that the SDT consider equipment limitation be introduced similar to PRC-024 where equipment limitation is allowed but adequately reported.

MRO NSRF recommends the SDT consider alternative methods/requirements be provided as an option for the equipment that are not capable of meeting the recording requirements. Refer to

PRC-025, Options 5a and 5b as an example, where 5b option was introduced to eliminate costly replacements.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Thank you for your comments.

R8 has been revised for clarity, and the same revisions have been applied to PRC-002-5, R12.

In the next draft, the process for seeking an extension has been heavily revised and moved from R9 to the Implementation Plan.

These brackets are part of the NERC standard development process. Once the standard is approved by FERC, the phrase “the effective date of this standard” is replaced by the actual effective date of the standard.

R9 did not deal with faulty equipment. The intent of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline. Requests for extension must be approved by the Regional Entity, so they would not be valid without being filed.

All individual unit requirements have been deleted from the latest draft.

In summary response to your remaining comments:
This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared. In setting the data recording parameters, the SDT has reviewed the NERC disturbance reports, consulted with manufacturers, and considered the burden to industry. The data requirements are addressed in the PRC-028 Technical Rationale. All individual unit requirements have been removed from the latest draft, and meeting these requirements should be less of an issue with equipment used to monitor at the plant level.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	

WEC Energy Group supports the comments of both the MRO NSRF and the NAGF.

Likes 0	
Dislikes 0	

Response	
Thank you. Please see responses to MRO NSRF and NAGF comments.	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	
Document Name	
Comment	
RF appreciates the continued efforts of the SDT on this project. RF recommends adding a justification for the addition of CSV file formats to PRC-002 R11 Part 11.4 to the Technical Rationale. RF also recommends considering whether the addition of CSV should be limited to Dynamic Disturbance Recording (DDR) data, with the use of COMTRADE remaining required for all Fault Recording (FR) data.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT did revise to limit CSV to DDR data only and has plans to review the Technical Rationale.	
Carver Powers - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	

We recognize that IBR's pose a reliability risk and that being able to monitor the events and have in depth data for a trip is very important. However, the granularity of the information being required by PRC-028 does not seem to be in step with what PRC-002 is asking for. Could this data be captured by TOs who have a greater situational awareness?

Likes 0	
Dislikes 0	

Response

Thank you for your comment. FERC Order 901 directs that data not only be available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models. The requirements of the two standards cannot be directly compared. The responsible party for the required data is the equipment owner registered with NERC, which in most cases is going to be the GO.

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

The cost and burden of the proposed PRC-028 requirements are not believed justified by the reliability benefits it would provide.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Thank you for your comment. FERC Order 901 mandates that disturbance monitoring data be available to analyze IBR response to BES disturbances, evaluate IBR performance, and validate IBR models.

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), the MRO NSRF, and the NAGF for question #5.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see responses to EEI, MRO NSRF, and NAGF comments.	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
The following comments are for the PRC-002-5 standard: 1) Replace "Hydro-Québec Interconnection" with "Québec Interconnection". 2) Correct VSL table for R1 Moderate and High since the examples don't cover exactly 70% et 80%. Suggest replacing with"more than 70%, but less than or equal to 80%" for the Moderate VSL and "more than 60%, but less than or equal to 70%" for the high VSL. 3) Severe VSL E11 : should read "…provided the requested data more than 60 days" instead of "…failed to provide the requested data more than 60 calendar days". 4) Attachment 1 step 3: "If the list has 11 or fewer buses, proceed to step 7" should be moved to step 2 with the following text "If the resulting list has 11 or fewer buses, proceed to Step 7".	

The following comments are for the PRC-028-1 standard: We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06. No changes are made in Attachment 1, as steps written as-is would result in same outcome with proposed revision. We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as 2020-02 (PRC-029) and 2023-02(PRC-030). Are we to understand that this is the recommended text for the facilities section in regards to the standards where IBRs are applicable and that the other projects will ensure consistent language use in line iwth the recent ROP and GO/GOP definition revisions?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. In PRC-002, “Hydro-Quebec Interconnection" is replaced with "Quebec Interconnection”. VSLs for R1 and R11 are also revised as suggested. Thank you for your comment. The language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process. The other standards referenced in your comment will likely follow similar format in upcoming revisions.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	
Response	
Thank you.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE supports EEI comments submitted for question 5 regarding Data Retention Requirements for PRC-002 & PRC-028.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to EEI comments.	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	

Thank you. Please see response to EEI comments.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	
Did the standard drafting team consider CIP implications (risks)?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Monitoring equipment alone has no CIP impact. So, the SDT did not consider this an issue. If/how an entity chooses to network monitoring equipment could have a CIP impact, but that is outside the scope of this SDT.	
Colby Galloway - Southern Company - Alabama Power Company - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
For PRC-028, R8, it is not clear whether the CAP implementation in the 2nd bullet item must be complete at the end of the 90-days specified in the R8 text. If so, what then is the difference in the first bullet (restoring the capability) and why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit? In PRC-028, R9.5, does the request to extend the time provided refer to any changes made to an original CAP timeline? There are no other deadlines for completing any R9 CAP.	

CAPs documentation specifications and submittals to the RE are purely administrative and should be removed from the requirements list. A simple requirement to fix any faulty equipment will accomplish the intent of PRC-028, R8 and R9. An audit can check to ensure that all broken equipment was handled properly.

What dictates a "ride-thru" event in PRC-028, R1, the IBR mode status? Clarity is recommended.

In PRC-028, R1.2 and R1.3 remove the unnecessary brackets "[]" surrounding the "effective date of this standard".

PRC-028, R1.3 has an *"if capable of recording"* clause. If the inverter is incapable of recording certain data, does the SDT contemplate an "exemption process"?

Why does PRC-028, R2.2.1 need to be the IBR Unit transformer HV side versus the LV side?

Southern Company is in agreement with EEI, recommending that the IBR and IBR Unit definitions should be removed from PRC-002 and PRC-028 because the associated SAR does not provide this SDT with the authority to develop or adopt a definition that is currently unapproved. Moreover, once these definitions are approved and added to the Glossary of Terms there will be no need for inclusion of the definitions within these Reliability Standards.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

R8 has been revised for clarity, and the same revisions have been applied to PRC-002-5, R12.

In the next draft, the process for seeking an extension has been heavily revised and moved from R9 to the Implementation Plan.

R9 did not deal with faulty equipment. The intent of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline. Requests for extension must be approved by the Regional Entity, so they would not be valid without being filed.

This requirement has been deleted from the latest draft.

These brackets are part of the NERC standard development process. Once the standard is approved by FERC, the phrase "the effective date of this standard" is replaced by the actual effective date of the standard.

This requirement has been deleted from the latest draft.

All individual unit requirements have been deleted from the latest draft.

The Applicability section has been edited and reformatted for clarity in the next draft, and the language used will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC RSC supports the project.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to EEI comments.	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	
Document Name	
Comment	
Eversource supports EEI's comment that the SDT should consider modifying the requirements for dynamic Disturbance recording (DDR) equipment in both PRC-002 and PRC-028 in order to permit responsible entities to either install DDR equipment or Phasor Measurement Units (PMUs) since PMU equipment capture disturbance data at equal or better rates, and have the added benefit of synchronizing disturbance data from other locations utilizing existing network communications.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to EEI comments.	

Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to EEI comments.	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	
Comment	
The following comments are for the PRC-002-5 standard: 1) Replace "Hydro-Québec Interconnection" with "Québec Interconnection". 2) Correct VSL table for R1 Moderate and High since the examples don't cover exactly 70% et 80%. Suggest replacing with" more than 70%, but less than or equal to 80%" for the Moderate VSL and "more than 60%, but less than or equal to 70%" for the high VSL. 3) Severe VSL E11 : devrait lire "...provided the requested data more than 60 days" instead of "...failed to provide the requested data more than 60 calendar days". 4) Attachment 1 step 3: "If the list has 11 or fewer buses, proceed to step 7" should be moved to step 2 with the following text "If the resulting list has 11 or fewer buses, proceed to Step 7".	

The following comments are for the PRC-028-1 standard:

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.

We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as 2020-02 (PRC-029) and 2023-02(PRC-030). Are we to understand that this is the recommended text for the facilities section in regards to the standards where IBRs are applicable and that the other projects will ensure consistent language use?

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

Thank you for your comment. The language used in the Applicability section of the next draft has been revised. It will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process. The other standards referenced in your comment will likely follow similar format in upcoming revisions.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment

The SDT needs to coordinate with other active IBR driven NERC Projects to avoid conflicts and duplications of requirements.

PRC-028 needs to align with PRC-002 in regards to synchronized clock accurracy within +/- 2 milliseconds vs. +/- 1 millisecond.

Also, data retention requirements in PRC-028 need to align with PRC-002 which has 10 days instead of 20 days.

The RC should have oversite of the placement of DDR equipment at IBR facilities as in PRC-002.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The PRC-028, PRC-029, & PRC-030 and their NERC facilitators are in close contact.

In summary response to your other comments, this SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared. Please see the Technical Rationale for discussion of the monitoring requirements.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

Including post-approval references (i.e. "the effective date of this standard") should not be considered as appropriate. Essentially this is grandfathering in the operational and reliability risk of not having appropriate data. The use of "if capable of recording" will be a pivotal point to consider when reviewing equipment for grandfathered IBR Units. Should be noted that "capable" does not equate to non-implementation of recording which could be a choice. With feeder lengths and determination of feeder length varying, the 90% criteria will possibly exclude feeders and significant numbers of IBR Units. If one feeder is 10 miles long and two others at same Inverter-Based Resource are 8.9 miles long only one IBR unit with SER (per Parts 1.2/1.3)/FR (per Part 2.2) data will be required to be compliant on the 10 mile feeder. If that one IBR unit is offline, where is the risk being mitigated? To ensure compliance, CMEP staff will have to ascertain applicability based on the criteria within the Requirement (i.e., entities will have to have documentation explaining their determination.) Non-BES Inverter-Based Resources will be even more difficult to apply the criteria.

The Technical Rationale picture/examples are good and clearly show that only one IBR Unit will need disturbance monitoring data to be compliant. One IBR unit's data may still not allow for detailed analysis of events. Would reconsider Example 3's use of BES definition references in light of the definitions proposed for Inverter-Based Resources and IBR Units. Based on the Technical Rationale, to evaluate compliance for IBR units for SER, FR, and DDR data Regional Entities must access event analysis data. In PRC-002 there is a need to capture DDR for stability SOLs and Elements included in an IROL. Please confirm that the RC can identify those situations for BES and non-BES IBRs (without considering any commercial operation date limitations) which would require DDR installation. Those situations exist and the risk needs mitigated.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. All individual unit requirements have been removed from the latest draft.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
IBR & Unit IBR Definitions: The IBR and IBR Unit definitions should be removed from PRC-002 and PRC-028 because the associated SAR does not provide this SDT with the authority to develop or adopt a definition that is currently unapproved. Moreover, once these definitions are approved and added to the Glossary of Terms there will be no need for inclusion of the definitions within these Reliability Standards. **DDR Requirements for PRC-002 & PRC-028** EEI also suggests that consideration should be given to modifying the requirements for dynamic Disturbance recording (DDR) equipment in both PRC-002 and PRC-028 in order to permit responsible entities to either install DDR equipment or Phasor Measurement Units (PMUs) since	

PMU equipment capture disturbance data at equal or better rates, and have the added benefit of synchronizing disturbance data from other locations utilizing existing network communications.

Data Retention Requirements for PRC-002 & PRC-028

EEI does not agree that the data retention requirements for PRC-002 (see Requirement R11 - 10 days) and PRC-028 (Requirement R7 – 20 days) should be different. Having two different data retention requirements for two Reliability Standards that have the exact same purpose is unjustified. Given the currently enforceable version of PRC-002 has a 10 day retention period, PRC-028 should have the same data retention period.

Reliability Coordinator Responsibilities for PRC-028

EEI suggests that the RC should be provided with oversight responsibilities for the placement of DDR equipment, even at IBR facilities. While EEI understands that the desire is to have DDR equipment at all IBR Facilities, as more of these facilities are added to the BPS, it is likely that there will be clusters of IBR facilities in some areas diminishing the need for this equipment at all of these facilities. We further note that the cost of this equipment is significant, and consideration should be given to the actual need and the RC would be the best judge to make this determination.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The Applicability section has been edited and reformatted for clarity in the next draft, and the language used will not include any in progress definitions or the non-BES IBRs affected by the Rules of Procedure revision process.

DDR refers to the type of data. As long as the equipment meets the specified requirements in R4 and R5, it does not matter if it is a DFR, DDR, PMU, or something else. The SDT will review the PRC-028 Technical Rationale for opportunities to clarify.

PRC-002 and PRC-028 do not have the exact same purpose. FERC Order 901 mandates that disturbance monitoring data be available not only to analyze IBR response to BES disturbances, similar to what PRC-002 does for synchronous machines, but also to evaluate IBR performance and validate IBR models. The requirements of the two standards cannot be directly compared. Also see the PRC-028 Technical Rationale.
Michael Johnson - Michael Johnson On Behalf of: 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 provides the following: As currently drafted, PRC-028 does not contain the methodology like PRC-002 to determine if SER/FR is required. However, the DT has added, "elements associated with IBRs with an aggregate nameplate rating of 20 MVA and connecting to a voltage greater than or equal to 60 kV." Therefore, PG&E agrees with EEI input that "Elements to non-BES IBR units and BES IBR units" is too broad and the manner with which EEI has clarified the facilities to which the standard is applicable.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Please see the response to EEI.
Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Thank you. Please see the response to EEI comments.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	
Document Name	

Comment

TAL believes the threshold of 20MW for a facility to be required to install DDR equipment is going to put a lot of burden on the utilities with very little gain for the BES.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The language used in the Applicability section of the next draft has been revised and will not include the non-BES IBRs affected by the Rules of Procedure revision process.

Lori Frisk - Lori Frisk On Behalf of: Hillary Creurer, Allete - Minnesota Power, Inc., 1; - Lori Frisk

Answer	
Document Name	

Comment

Minnesota Power supports MRO NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Thank you. Please see the response to MRO NSRF comments.

Megan Melham - Decatur Energy Center LLC - 5

Answer	
Document Name	

Comment

Capital Power supports the comments submitted by NAGF.

The NAGF notes that Project 2021-04 needs to be closely coordinated with other active NERC IBR related projects to ensure there is no conflict and/or duplication of efforts. The NAGF recommends that NERC publish a guideline/roadmap to demonstrate how all the on-going and pending IBR work activities fit together so that industry can understand how these efforts will enhance BPS/BES reliability. For example, why is it necessary for PRC-028 to be effective prior to other new IBR standards (i.e., PRC-029/PRC-030)?

In addition, for the proposed Requirement R8, it is not clear whether or not the CAP referenced in the 2nd bullet item must be complete at the end of the 90 days. If so, what then is the difference between that and the first bullet (restoring the capability). Also, why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit? Further, the CAPs documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment should accomplish the intent of R8 & R9.

The NAGF has the following comments\questions regarding Requirement R3:

• What is the driver for the 2 seconds length and the 64 samples/sec recording requirements? Existing FR equipment typically has a maximum recording time of 60 cycles and maximum of 16 or 32 samples/sec. The proposed recording requirements are not consistent with similar requirements of PRC-002 (30 cycles & 16 samples/sec).

• Requirement 3.2 will be difficult to achieve for older IBRs. FR recording equipment will need to be added to meet this requirement. Meeting these requirements at the inverter/controller level will be challenging. • Did the SDT reach out to various manufacturers to confirm the equipment capability and more importantly, are the changes/updates available that can meet this requirement? • Should equipment limitation be introduced as one of the requirements, similar to PRC-024 where equipment limitation is allowed but adequately reported? • Should an alternative method/requirement be provided as an option for equipment that is not capable of meeting the recording requirements? Refer to PRC-025, Options 5a and 5b as an example, where 5b option was introduced to eliminate costly replacements.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to NAGF comments.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Marty Hostler - Northern California Power Agency - 4	

Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
It is unclear as to what constitutes a "ride-through operation" of an IBR Unit in R1.2 and R1.3. Is this intended to be a reference to "no trip zone" identified in PRC-024? If so, as PRC-024 is not currently applicable to non-BES IBRs, how is this identified for those facilities? We believe additional guidance is needed for these requirements. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you. Individual unit requirements have been deleted from the latest draft.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	

Answer	
Document Name	
Comment	

For R8, it is not clear whether the CAP implementation referenced in the 2nd bullet item must be complete at the end of the 90 days specified in the R8 text. If so, what then is the difference in the first bullet (restoring the capability) and why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit?

In R9.5 does the request to extend the time provided refer to any changes made to an original CAP timeline? (there are no other deadlines for completing any R9 CAP)

In R1.2 and R1.3 remove the unneeded brackets [ ] surrounding "the effective date of this standard".

CAPS documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment will accomplish the intent of R8 & R9. An audit can check to ensure that all broken equipment was handled properly.

What dictates a "ride-thru" event in R1? The IBR mode status?

Why is R2.2.1 needed to be the IBR Unit transformer HV side versus the LV side?

Based on research for the last ballot on the costs of having this on each feeder at a wind farm. This doesn't include solar IBRS. MRO NSRF estimates that the cost of installing DFR equipment on the high side of a pad mounted transformer at the base of a wind turbine in the last 10% of an existing wind turbine feeder will be $300-450k or 2-3 times the cost of installing the same equipment in an existing substation.

It is not understood what drives the 2 seconds length and the 64 samples/sec recording requirements. Existing FR equipment typically has a maximum recording time of 60 cycles and maximum of 16 or 32 samples/sec. Both of these are not consistent with similar requirements of PRC-002 (30 cycles & 16 samples/sec).

3.2 will be difficult to achieve for older IBRs. FR recording equipment will need to be added to meet this requirement. Meeting these requirements at the inverter/controller level will be challenging. PacifiCorp recommends that the SDT reach out to various manufacturers to confirm the equipment capability and if any changes/updates that may be necessary for equipment can meet this requirement will become available. PacifiCorp recommends that the SDT consider equipment limitation be introduced similar to PRC-024 where equipment limitation is allowed but adequately reported. PacifiCorp recommends the SDT consider alternative methods/requirements be provided as an option for the equipment that are not capable of meeting the recording requirements. Refer to PRC-025, Options 5a and 5b as an example, where 5b option was introduced to eliminate costly replacements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. R8 has been revised for clarity, and the same revisions have been applied to PRC-002-5, R12. In the next draft, the process for seeking an extension has been heavily revised and moved from R9 to the Implementation Plan. These brackets are part of the NERC standard development process. Once the standard is approved by FERC, the phrase “the effective date of this standard” is replaced by the actual effective date of the standard.	

R9 did not deal with faulty equipment. The intent of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline. Requests for extension must be approved by the Regional Entity, so they would not be valid without being filed.

All individual unit requirements have been deleted from the latest draft.

In summary response to your remaining comments:
This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared. In setting the data recording parameters, the SDT has reviewed the NERC disturbance reports, consulted with manufacturers, and considered the burden to industry. The requirements are addressed in the PRC-028 Technical Rationale. All individual unit requirements have been removed from the latest draft, and meeting these requirements should be less of an issue with equipment used to monitor at the plant level.

Dave Krueger - SERC Reliability Corporation - 10

Answer	
Document Name	

Comment

On behalf of the SERC Generator Working Group:

- General comment: Should there be an assessment to determine which facilities this monitoring equipment should be installed on rather than just requiring for every IBR Unit
- R1: The data required in 1.2.1-4 and 1.3.1-4 are not currently available in all manufacturers
- R8: The two bullets say the same thing. Should it be that the CAP is submitted within 90 days and then implemented after? Otherwise implementing it within 90 days is the same as restoring the recording capability.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

- This SDT has been tasked with not only making sure data is available to analyze IBR response to BES disturbances, but also, with the added directives of FERC Order 901, ensuring disturbance data is available to evaluate IBR performance and validate IBR models. That expanded scope makes monitoring at all IBRs important.
- All individual unit requirements have been deleted from the latest draft.
- R8 has been revised for clarity, and the same revisions have been applied to PRC-002-5, R12.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	
Document Name	
Comment	

PRC-028-1 Requirement R4 requires a DDR for the MPT of every 20+ MVA IBR with a connection point at a voltage of 60kV or greater . It is unclear whether these DDR (at least for BES IBR) should be included in the DDR coverage calculation in PRC-002-5 Requirement R5 Part 5.2. The SRC recommends that PRC-002-5 Requirement R5 be revised to clarify if any or all or none of the DDRs required by PRC-028-1 Requirement R4 are required (or allowed) to be included in the minimum DDR coverage under PRC-002-5 Requirement R5 Part 5.2.

PRC-028-1 Requirement R3 does not place minimum triggering thresholds on neutral overcurrent (Part 3.1.3.1), AC phase overvoltage and undervoltage (Parts 3.1.3.2 and 3.2.3.1), or overfrequency or underfrequency (Part 3.2.3.2). Improper threshold settings have led to event data being unavailable in instances where it would have been valuable for analysis. The SRC recommends that minimum triggering thresholds be added to the requirements to ensure this data is captured reliably.

PRC-028-1 Requirement R7, Part 7.2 requires that data subject to Part 7.1 be provided to the requesting entity within 30 calendar days of a request, yet Part 7.1 only requires the data to be retrievable for a period of 20 calendar days. The SRC recommends that the period to provide data under Part 7.2 be half of the data retention period under Part 7.1. In response to data requests, SRC members have often received data that does not fully cover the requested timeframes or that is incomplete and missing information. Ensuring that the response period under Part 7.2 is half of the data retention period under Part 7.1 would allow time for these types of errors to be detected and corrected before the data retention period expires and the data is lost.

PRC-028-1 Requirement R1, Part 1.3 requires currently in operation IBR units to record certain data unless they are not “capable of recording.” The SRC requests that the SDT clarify what it means for an IBR Unit to not be capable of recording the required data, as the proposed language could be read to include IBR Units that have the technical capability to record the required data, but failed to record the data due to a malfunction or due to being temporarily out of service.

Requirement R5 of PRC-002-5 Includes some unnecessary administrative compliance burdens. A GO with a 500+ MVA unit or 300+ MVA unit within a 1000 MVA plant should already know that they are required to install DDR without a specific RC requirement to provide notification of their DDR obligation.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

PRC-002-5 does not apply to IBRs, so the DDR requirements in PRC-028 do not count toward PRC-002. No elements should be covered under both standards as this would set up a double jeopardy situation.

The SDT is leaving trigger settings up to engineering judgement.

Revision to part 7.2 has been made to shorten the response time.

This requirement has been deleted from the latest draft.

This is outside the scope of this SDT. We did not change any of the monitoring requirements in PRC-002.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI offer the following additional comments:

IBR & Unit IBR Definitions:

The IBR and IBR Unit definitions should be removed from PRC-002 and PRC-028 because the associated SAR does not provide this SDT with the authority to develop or adopt a definition that is currently unapproved. Moreover, once these definitions are approved and added to the Glossary of Terms there will be no need for inclusion of the definitions within these Reliability Standards.

DDR Requirements for PRC-002 & PRC-028

EEI also suggests that consideration should be given to modifying the requirements for dynamic Disturbance recording (DDR) equipment in both PRC-002 and PRC-028 in order to permit responsible entities to either install DDR equipment or Phasor Measurement Units (PMUs) since PMU equipment capture disturbance data at equal or better rates, and have the added benefit of synchronizing disturbance data from other locations utilizing existing network communications.

Data Retention Requirements for PRC-002 & PRC-028

EEI does not agree that the data retention requirements for PRC-002 (see Requirement R11 - 10 days) and PRC-028 (Requirement R7 – 20 days) should be different. Having two different data retention requirements for two Reliability Standards that have the exact same purpose is unjustified. Given the currently enforceable version of PRC-002 has a 10 day retention period, PRC-028 should have the same data retention period.

Reliability Coordinator Responsibilities for PRC-028

EEI suggests that the RC should be provided with oversight responsibilities for the placement of DDR equipment, even at IBR facilities. While EEI understands that the desire is to have DDR equipment at all IBR Facilities, as more of these facilities are added to the BPS, it is likely that there will be clusters of IBR facilities in some areas diminishing the need for this equipment at all of these facilities. We further note that the cost of this equipment is significant, and consideration should be given to the actual need and the RC would be the best judge to make this determination.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The IBR-related definitions have been removed from the upcoming draft.

DDR is intended to refer to the type of data. As long as the data is sufficient to meet the specified requirements, the type of installed equipment does not matter; it can be a DFR, DDR, PMU, or something else. The SDT will review the PRC-028 Technical Rationale for opportunities to clarify.

Combined response to the last two comments: PRC-002 and PRC-028 do not have the exact same purpose. FERC Order 901 mandates that disturbance monitoring data be available not only to analyze IBR response to BES disturbances, similar to what PRC-002 does for synchronous machines, but also to evaluate IBR performance and validate IBR models. The requirements of the two standards cannot be directly compared. Also, see the PRC-028 Technical Rationale for discussion of the differing requirements.

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see response to NPCC Regional Standards Committee's comments.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

In previous response to comments, the drafting team suggested that “FERC Order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs.” In fact, FERC Order 901 states that the more limited approach taken in PRC-002 “[has] been adequate to provide the data necessary to analyze major system events in the past.” Invenergy recommends the SDT develop a methodology similar to PRC-002 Attachment 1 that Transmission Owners and Reliability Coordinators can utilize to identify key nodes where disturbance monitoring equipment should be deployed.

The SER data required in R1.2.1. and R1.2.2. is generic and should be refined to target specific categories of fault codes and alarms so as not to overburden local storage of the data. On that point, 20 days of retrievable data is simply beyond the capabilities of some inverters. Invenergy recommends the data storage requirement in R7.1. be reduced to 10 days to align with PRC-002 R11.1. Furthermore, the various requested IBR Unit level data, sampling rates, time sync, and data format present many technical challenges for existing IBRs, some of which will have no solution other than replacement of the IBR Unit. As such, we suggested changes to R9 to account for these equipment limitations in response to Question 4.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The section of FERC Order 901 quoted above is only the first half of a sentence that ends with “… NERC has found that the existing disturbance monitoring equipment is not sufficient (e.g., lack of high speed data captured at the IBR or plant level controller and low resolution time stamping of inverter sequence of event recorder information) to analyze the widespread system events that have become more common since 2016.” This justifies the development of a modified approach as the SDT has stated.

This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared. See the PRC-028-1 Technical Rationale for discussion of the requirements.

The IBR Unit level monitoring requirements have been removed from the next draft of the standard, and meeting these requirements should be less of an issue with equipment used to monitor at the plant level.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

The NAGF notes that Project 2021-04 needs to be closely coordinated with other active NERC IBR related projects to ensure there is no conflict and/or duplication of efforts. The NAGF recommends that NERC publish a guideline/roadmap to demonstrate how all the on-going and pending IBR work activities fit together so that industry can understand how these efforts will enhance BPS/BES reliability. For example, why is it necessary for PRC-028 to be effective prior to other new IBR standards (i.e., PRC-029/PRC-030)?

In addition, for the proposed Requirement R8, it is not clear whether or not the CAP referenced in the 2nd bullet item must be complete at the end of the 90 days. If so, what then is the difference between that and the first bullet (restoring the capability). Also, why might the Regional Entity need to know of a repair plan in progress that will be completed before the 90-day limit? Further, the CAPs documentation specifications and submittals to the RE are purely administrative and should be removed from the requirement list. A simple requirement to fix any faulty equipment should accomplish the intent of R8 & R9.

The NAGF has the following comments\questions regarding Requirement R3:

- *What is the driver for the 2 seconds length and the 64 samples/sec recording requirements? Existing FR equipment typically has a maximum recording time of 60 cycles and maximum of 16 or 32 samples/sec. The proposed recording requirements are not consistent with similar requirements of PRC-002 (30 cycles & 16 samples/sec).*
- *Requirement 3.2 will be difficult to achieve for older IBRs. FR recording equipment will need to be added to meet this requirement. Meeting these requirements at the inverter/controller level will be challenging.*
- *Did the SDT reach out to various manufacturers to confirm the equipment capability and more importantly, are the changes/updates available that can meet this requirement?*
- *Should equipment limitation be introduced as one of the requirements, similar to PRC-024 where equipment limitation is allowed but adequately reported?*
- *Should an alternative method/requirement be provided as an option for equipment that is not capable of meeting the recording requirements? Refer to PRC-025, Options 5a and 5b as an example, where 5b option was introduced to eliminate costly replacements.*

Likes 0	

Dislikes 0	

Response

Thank you for your comments.

- PRC-028, PRC-029, & PRC-030 all have to be delivered to FERC by 11/1/2024 and fully effective and enforceable no later than January 1, 2030 per FERC Order 901 and NERC's Response to it. NERC has published multiple resources on its website regarding the standards roadmap and workplan. These drafting teams and their NERC facilitators communicate regularly.
- The intent of R8 is to prioritize the repair of equipment. The SDT has revised PRC-028, R8 for clarity, and the same revisions have been applied to PRC-002-5, R12. Please, also refer to the PRC-028 Technical Rationale.
- PRC-028, R9 did not deal with faulty equipment. The intent of R9 was to allow more time for entities that may have circumstances beyond their control that delay installation of DME beyond the stated implementation deadline. Requests for extension must be approved by the Regional Entity, so they would not be valid without being filed. In the next draft, the process for seeking an extension has been heavily revised and moved from R9 to the Implementation Plan.
- Regarding PRC-028, R3:

  This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also with ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared. In setting the data recording parameters, the SDT has reviewed the NERC disturbance reports, consulted with manufacturers, and considered the burden to industry. The data requirements are addressed in the PRC-028 Technical Rationale. All individual unit requirements have been removed from the latest draft, and meeting these requirements should be less of an issue with equipment used to monitor at the plant level.

Mike Magruder - Avista - Avista Corporation – 1

Answer	
Document Name	

Comment

Overall wording for the sections mentioned above for PRC-028 should be cleaned up. Terms like IBR should have formal definitions, outside of PRC-028 in the NERC Glossary of Terms.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The IBR-related definitions have been removed from the upcoming draft.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	
In previous response to comments, the drafting team suggested that "FERC Order 901 reinforces the approach taken by this SDT to require monitoring for all IBRs." In fact, FERC Order 901 states that the more limited approach taken in PRC-002 "[has] been adequate to provide the data necessary to analyze major system events in the past." Invenergy recommends the SDT develop a methodology similar to PRC-002 Attachment 1 that Transmission Owners and Reliability Coordinators can utilize to identify key nodes where disturbance monitoring equipment should be deployed. The SER data required in R1.2.1. and R1.2.2. is generic and should be refined to target specific categories of fault codes and alarms so as not to overburden local storage of the data. On that point, 20 days of retrievable data is simply beyond the capabilities of some inverters. Invenergy recommends the data storage requirement in R7.1. be reduced to 10 days to align with PRC-002 R11.1. Furthermore, the various requested IBR Unit level data, sampling rates, time sync, and data format present many technical challenges for existing IBRs, some of which will have no solution other than replacement of the IBR Unit. As such, we suggested changes to R9 to account for these equipment limitations in response to Question 4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The section of FERC Order 901 quoted above is only the first half of a sentence that ends with "…	

NERC has found that the existing disturbance monitoring equipment is not sufficient (e.g., lack of high speed data captured at the IBR or plant level controller and low resolution time stamping of inverter sequence of event recorder information) to analyze the widespread system events that have become more common since 2016." This justifies the development of a modified approach as the SDT has stated.

This SDT has been tasked not only with making sure data is available to analyze IBR response to BES disturbances similar to what PRC-002 does for synchronous machines, but also ensuring disturbance data is available to evaluate IBR performance and validate IBR models per FERC Order 901. The requirements of the two standards cannot be directly compared. See the PRC-028-1 Technical Rationale for discussion of the requirements.

The IBR Unit level monitoring requirements have been removed from the next draft of the standard, and meeting these requirements should be less of an issue with equipment used to monitor at the plant level.

Reminder
Standards Announcement
Project 2021-04 Modifications to PRC-002 - Phase II

Additional Ballots and Non-binding Polls Open through April 11, 2024

Now Available

Additional ballots for **Project 2021-04 Modifications to PRC-002 - Phase II** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, April 11, 2024** for the following standards and implementation plan:

- PRC-002-5 – Disturbance Monitoring and Reporting Requirements
- PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- Implementation Plan

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

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.

Note: Votes cast in previous ballots will not carry over to additional ballots. It is the responsibility of the registered voter in the ballot pools to place votes again. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *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 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 2021-04 Modifications to PRC-002 observer list” 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

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Open through April 11, 2024

Now Available

A 25-day formal comment period for **Project 2021-04 Modifications to PRC-002 - Phase II** is open through **8 p.m. Eastern, Thursday, April 11, 2024** for the following standards and implementation plan:

- PRC-002-5 – Disturbance Monitoring and Reporting Requirements
- PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- Implementation Plan

The standard drafting team's considerations of the responses received from the previous comment period are reflected in these drafts of the standards.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact **ballotadmin@nerc.net** to assist with the removal of any duplicate registrations.

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.*

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Next Steps
Additional ballots for the standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 2 - 11, 2024**.

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 2021-04 Modifications to PRC-002 observer list” in the Description Box.

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Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 AB 2 ST
Voting Start Date: 4/2/2024 12:01:00 AM
Voting End Date: 4/11/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 245
Total Ballot Pool: 274
Quorum: 89.42
Quorum Established Date: 4/11/2024 2:00:18 PM
Weighted Segment Value: 79.46

Actions

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	74	1	50	0.862	8	0.138	0	5	11
Segment: 2	8	0.6	5	0.5	1	0.1	0	0	2
Segment: 3	60	1	46	0.836	9	0.164	0	3	2
Segment: 4	14	1	5	0.455	6	0.545	0	3	0
Segment: 5	68	1	47	0.825	10	0.175	0	1	10
Segment: 6	43	1	29	0.829	6	0.171	0	4	4
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: 10	6	0.6	6	0.6	0	0	0	0	0
Totals:	274	6.3	189	5.006	40	1.294	0	16	29

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A

1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer	Lori Frisk	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A

1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Affirmative	N/A
6	Manitoba Hydro	Kelly Bertholet		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	AEP	Leshel Hutchings		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted

1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
6	AEP	Mathew Miller		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Third-Party Comments
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Alan Kloster	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A

10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
5	Santee Cooper	Don Cribb		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A

3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A

5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A

5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Third-Party Comments
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A

6	Seminole Electric Cooperative, Inc.	Bret Galbraith	Abstain	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 AB 2 ST
Voting Start Date: 4/2/2024 12:01:00 AM
Voting End Date: 4/11/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 241
Total Ballot Pool: 270
Quorum: 89.26
Quorum Established Date: 4/11/2024 2:05:03 PM
Weighted Segment Value: 50.03

Actions

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	72	1	23	0.451	28	0.549	0	10	11
Segment: 2	8	0.6	5	0.5	1	0.1	0	0	2
Segment: 3	59	1	24	0.462	28	0.538	0	5	2
Segment: 4	14	1	2	0.2	8	0.8	0	4	0
Segment: 5	68	1	22	0.423	30	0.577	0	6	10
Segment: 6	42	1	16	0.516	15	0.484	0	7	4
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: 10	6	0.6	5	0.5	1	0.1	0	0	0
Totals:	270	6.3	98	3.152	111	3.148	0	32	29

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Negative	Third-Party

					Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer	Lori Frisk	Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		None	N/A

3	Xcel Energy, Inc.	Nicholas Friebel	Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan	Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya	Affirmative	N/A
3	Great River Energy	Michael Brytowski	Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez	None	N/A
1	Great River Energy	Gordon Pietsch	Negative	Third-Party Comments
3	WEC Energy Group, Inc.	Christine Kane	Negative	Comments Submitted
1	National Grid USA	Michael Jones	Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar	Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer	Abstain	N/A
5	Great River Energy	Jacalynn Bentz	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch	None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin	Negative	Comments Submitted
5	National Grid USA	Robin Berry	Negative	Third-Party Comments
3	Ameren - Ameren Services	David Jendras Sr	Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey	Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan	Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy	Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder	Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	None	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers	Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer	Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon	Affirmative	N/A

6	Manitoba Hydro	Kelly Bertholet		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
3	AEP	Leshel Hutchings		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
6	AEP	Mathew Miller		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Third-Party Comments
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted

1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Abstain	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
					Third-Party

5	Nebraska Public Power District	Ronald Bender		Negative	Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
5	Santee Cooper	Don Cribb		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party

					Comments
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Abstain	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	Lakeland Electric	Steven Marshall		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Abstain	N/A

3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
5	Leeward Renewable Energy	Rob Robertson		Negative	Comments Submitted
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A

4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Third-Party Comments
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II Implementation Plan AB 2 OT
Voting Start Date: 4/2/2024 12:01:00 AM
Voting End Date: 4/11/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 241
Total Ballot Pool: 274
Quorum: 87.96
Quorum Established Date: 4/11/2024 2:13:13 PM
Weighted Segment Value: 66.61

Actions

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	74	1	34	0.596	23	0.404	0	6	11
Segment: 2	7	0.5	5	0.5	0	0	0	0	2
Segment: 3	60	1	33	0.623	20	0.377	0	3	4
Segment: 4	14	1	6	0.545	5	0.455	0	3	0
Segment: 5	68	1	31	0.585	22	0.415	0	3	12
Segment: 6	44	1	22	0.647	12	0.353	0	6	4
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: 10	6	0.4	4	0.4	0	0	0	2	0
Totals:	274	6	136	3.997	82	2.003	0	23	33

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted

3	Lincoln Electric System	Sam Christensen		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer	Lori Frisk	Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A

5	PPL - Louisville Gas and Electric Co.	Julie Hostrander	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan	Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya	Affirmative	N/A
3	Great River Energy	Michael Brytowski	Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez	None	N/A
1	Great River Energy	Gordon Pietsch	Negative	Third-Party Comments
3	WEC Energy Group, Inc.	Christine Kane	Negative	Comments Submitted
1	National Grid USA	Michael Jones	Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar	Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch	None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin	Affirmative	N/A
5	National Grid USA	Robin Berry	Negative	Third-Party Comments
3	Ameren - Ameren Services	David Jendras Sr	Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey	Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan	Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy	Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder	Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	None	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers	Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer	Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon	Negative	Comments Submitted
6	Manitoba Hydro	Kelly Bertholet	Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker	Negative	Third-Party Comments

1	New York Power Authority	Daniel Valle		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	AEP	Leshel Hutchings		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
6	AEP	Mathew Miller		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted

5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		None	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
					Third-Party

1	Nebraska Public Power District	Jamison Cawley		Negative	Comments
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
5	Santee Cooper	Don Cribb		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Affirmative	N/A

6	Austin Energy	Imane Mrini		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A

3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments

5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 | Non-Binding Poll AB 2 NB
Voting Start Date: 4/2/2024 12:01:00 AM
Voting End Date: 4/11/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 226
Total Ballot Pool: 266
Quorum: 84.96
Quorum Established Date: 4/11/2024 2:27:47 PM
Weighted Segment Value: 77.96

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	37	0.822	8	0.178	13	13
Segment: 2	7	0.5	4	0.4	1	0.1	0	2
Segment: 3	58	1	36	0.8	9	0.2	7	6
Segment: 4	14	1	5	0.455	6	0.545	3	0
Segment: 5	67	1	34	0.756	11	0.244	8	14
Segment: 6	42	1	23	0.793	6	0.207	8	5
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: 10	6	0.5	5	0.5	0	0	1	0
Totals:	266	6.1	145	4.625	41	1.475	40	40

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		None	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer	Lori Frisk	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A

1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Abstain	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	AEP	Leshel Hutchings		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
6	AEP	Mathew Miller		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
	NiSource - Northern Indiana Public Service				Comments

3	Co.	Steven Taddeucci		Negative	Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Alan Kloster	Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
	Southern Company - Southern Company				Comments

6	Generation	Ron Carlsen		Negative	Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
	Edison International - Southern California				

6	Edison Company	Stephanie Kenny		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A

5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted

1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A

[redacted]

Ballot Results

Comment: [View Comment Results]
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll AB 2 NB
Voting Start Date: 4/2/2024 12:01:00 AM
Voting End Date: 4/11/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 226
Total Ballot Pool: 261
Quorum: 86.59
Quorum Established Date: 4/11/2024 2:17:24 PM
Weighted Segment Value: 44.83

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	69	1	19	0.452	23	0.548	15	12
Segment: 2	7	0.5	4	0.4	1	0.1	0	2
Segment: 3	57	1	19	0.432	25	0.568	10	3
Segment: 4	14	1	2	0.2	8	0.8	4	0
Segment: 5	66	1	16	0.39	25	0.61	12	13
Segment: 6	41	1	12	0.462	14	0.538	10	5
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: 10	6	0.5	5	0.5	0	0	1	0
Totals:	261	6.1	78	2.936	96	3.164	52	35

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer	Lori Frisk	Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted

6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan	Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya	None	N/A
3	Great River Energy	Michael Brytowski	Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez	None	N/A
1	Great River Energy	Gordon Pietsch	Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane	Negative	Comments Submitted
1	National Grid USA	Michael Jones	Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar	Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer	Abstain	N/A
5	Great River Energy	Jacalynn Bentz	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Negative	Comments Submitted
3	National Grid USA	Brian Shanahan	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch	None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin	Negative	Comments Submitted
5	National Grid USA	Robin Berry	Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr	Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey	Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan	Abstain	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy	Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder	Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	None	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers	Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer	Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon	Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker	Negative	Comments Submitted
1	New York Power Authority	Daniel Valle	Affirmative	N/A
				Comments

5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
3	AEP	Leshel Hutchings		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
6	AEP	Mathew Miller		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A

10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Abstain	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A

3	Santee Cooper	Vicky Budreau		Abstain	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Abstain	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A

3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	Lakeland Electric	Steven Marshall		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A

10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A

4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A

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

PRC-002-5 is posted for a formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
25-day formal or informal comment period with additional ballot	March 18, 2024 – April 11, 2024
15-day formal or informal comment period with additional ballot	May 31, 2024 – June 14, 2024
10-day final ballot	September 15, 2024 – September 24, 2024
Board adoption	October 15, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-5
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
   - **4.2. Facilities:** BES Elements, excluding inverter-based resources.[1]
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-5, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[2] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-5, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES

[1] Disturbance monitoring and reporting requirements for inverter-based resources are addressed in PRC-028.

[2] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns directly connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Phase-to-neutral voltage for each phase of each specified BES bus.

3.2. Each phase current and the residual or neutral current for the following BES Elements:

3.2.1. Transformers that have a low-side operating voltage of 100 kV or above.

3.2.2. Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2. A minimum recording rate of 16 samples per cycle.

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1)

documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1. Synchronous generating resource(s) with:

5.1.1.1. Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2. Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2. Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3. Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5. Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2. Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1. One BES Element; and

5.2.2. One BES Element per 3,000 MW of the Reliability Coordinator’s historical simultaneous peak System Demand.

5.3. Notify all owners of identified BES Elements, within 90 calendar days of completion of Part 5.1, that their respective BES Elements require DDR data.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. One phase-to-neutral or positive sequence voltage.

6.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of the Reliability Standard PRC-002-2[3] and is not capable of continuous recording, triggered records

[3] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
o Quebec Interconnection	< -0.18125 Hz/sec	>0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.

11.3. SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. FR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5. DDR data will be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.6. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, upon the discovery of a failure of the recording capability for the SER, FR or DDR data: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1 for five calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5 for five

calendar years.

The Transmission Owner shall retain evidence of Requirement R6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12 for three calendar years.

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

		days, but less than or equal to 20 calendar days.	20 calendar days, but less than or equal to 30 calendar days.	
R2	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent, but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent, but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent, but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical

	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.
R4	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.
R5	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent, but less than 100 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by 30 calendar days or less.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent, but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 30 calendar	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent, but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 60 calendar days and less	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 90 calendar days.

	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.

R7	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.
R8	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent, but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent, but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent, but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60

	than 100 percent of the total recording properties as specified in Requirement R9.	equal to 80 percent of the total recording properties as specified in Requirement R9.	than or equal to 70 percent of the total recording properties as specified in Requirement R9.	percent of the total recording properties as specified in Requirement R9.
R10	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent, but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent, but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent, but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority.

	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided less than or equal to 70 percent of the data in the proper data format.
R12	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days

	calendar days after discovery of the failure.	days after discovery of the failure.	calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
R13		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months, but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months, but less	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

			than or equal to 12 months.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-5: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-5: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005.

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC Oder Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14, 2023	Effective Date	April 1, 2024
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored Bulk Electric System (BES) buses for SER and FR data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns. Refer to section 4.2 Facilities for exclusion.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three-phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three-phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three-phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete, and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more, but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three-phase short circuit MVA of the newly identified BES bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

<u>If the list has more than 11 BES buses:</u> SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three-phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other Disturbance Monitoring Equipment (DME) devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[4]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[4] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

PRC-002-5 is posted for a formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
25-day formal or informal comment period with additional ballot	March 18, 2024 – April 11, 2024
25-day formal or informal comment period with additional ballot	May 31, 2024 – June 14, 2024
10-day final ballot	September 15, 2024 – September 24, 2024
Board adoption	October 15, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

~~The term Inverter-Based Resource (IBR) refers to the proposed definition being developed under the Project 2020-06 Verifications of Models and Data for Generators.~~

~~As of this posting, this definition is:~~

~~**Inverter-Based Resource**: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell.~~

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-~~4~~5
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Owner

   4.1.3. Generator Owner

   4.2. Facilities: BES Elements, excluding ~~I~~inverter-~~B~~based ~~R~~resources.[1]
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-~~4~~5, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[2] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-~~4~~5, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

[1] Disturbance monitoring and reporting requirements for ~~I~~inverter-~~B~~based ~~R~~resources are addressed in PRC-028.

[2] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns directly connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Phase-to-neutral voltage for each phase of each specified BES bus.

3.2. Each phase current and the residual or neutral current for the following BES Elements:

3.2.1. Transformers that have a low-side operating voltage of 100 kV or above.

3.2.2. Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2. A minimum recording rate of 16 samples per cycle.

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1. Synchronous ~~machine based~~ generating resource(s) with:

5.1.1.1. Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2. Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2. Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3. Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5. Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2. Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1. One BES Element; and

5.2.2. One BES Element per 3,000 MW of the Reliability Coordinator’s historical simultaneous peak System Demand.

5.3. Notify all owners of identified BES Elements, within 90 calendar days of completion of Part 5.1, that their respective BES Elements require DDR data.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part

5.3. Evidence may include, but is not limited to letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. One phase-to-neutral or positive sequence voltage.

6.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of the Reliability

Standard PRC-002-2[3] and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ ~~Hydro-~~Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
○ ~~Hydro-~~Quebec Interconnection	< -0.18125 Hz/sec	>0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES

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[3] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.

11.3. SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. FR ~~and DDR~~ data will be provided in ~~either in CSV format or~~ electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

~~11.4.~~11.5. DDR data will be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

~~11.5.~~11.6. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, upon~~within 90 calendar days of~~ the discovery of a failure of the recording capability for the SER, FR or DDR data~~, either~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, for five calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12, for three calendar years.

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non- compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

		days, but less than or equal to 20 calendar days.	20 calendar days, but less than or equal to 30 calendar days.	
R2	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent, but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent, but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical

	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.
R4	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.
R5	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent, but less than 100 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by 30 calendar days or less.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent, but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 30 calendar	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent, but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 60 calendar days and less	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 90 calendar days.

	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.

R7	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.
R8	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent, but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent, but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent, but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60

	than 100 percent of the total recording properties as specified in Requirement R9.	equal to 80 percent of the total recording properties as specified in Requirement R9.	than or equal to 70 percent of the total recording properties as specified in Requirement R9.	percent of the total recording properties as specified in Requirement R9.
R10	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent, but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent, but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent, but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 ~~failed to~~ provided the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority.

	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided less than or equal to 70 percent of the data in the proper data format.
R12	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days

	calendar days after discovery of the failure.	days after discovery of the failure.	calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
R13		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

			than or equal to 12 months.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-~~4~~5: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-~~4~~5: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005.

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC Oder Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14, 2023	Effective Date	April 1, 2024
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored Bulk Electric System (BES) buses for SER and FR data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns. Refer to section 4.2 Facilities for exclusion.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three-phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three-phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three-phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete, and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three-phase short circuit MVA of the newly identified BES bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three-phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other Disturbance Monitoring Equipment (DME) devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[4]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[4] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

PRC-002-5 is posted for a formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
25-day formal or informal comment period with additional ballot	March 18, 2024 – April 11, 2024
15-day formal or informal comment period with additional ballot	May 31, 2024 – June 14, 2024
10-day final ballot	September 15, 2024 – September 24, 2024
Board adoption	October 15, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-54

3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.

4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Reliability Coordinator

    4.1.2. Transmission Owner

    4.1.3. Generator Owner

    4.2. **Facilities:** BES Elements, excluding inverter-based resources.[1]

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-54, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[2] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-54, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

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[1] Disturbance monitoring and reporting requirements for inverter-based resources are addressed in PRC-028.

[2] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns directly connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Phase-to-neutral voltage for each phase of each specified BES bus.

3.2. Each phase current and the residual or neutral current for the following BES Elements:

3.2.1. Transformers that have a low-side operating voltage of 100 kV or above.

3.2.2. Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2. A minimum recording rate of 16 samples per cycle.

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1. Synchronous ~~G~~generating resource(s) with:

5.1.1.1. Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2. Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2. Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3. Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5. Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2. Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1. One BES Element; and

5.2.2. One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3. Notify all owners of identified BES Elements, within 90 calendar days of completion of Part 5.1, that their respective BES Elements require DDR data.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part

5.3. Evidence may include, but is not limited to~~:~~ letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. One phase-to-neutral or positive sequence voltage.

6.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3. Real Power and Reactive Power flows expressed on a three~~-~~-phase basis corresponding to all circuits where current measurements are required.

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3. Real Power and Reactive Power flows expressed on a three~~-~~-phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of the Reliability

Standard PRC-002-2[3] and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o ~~Hydro-~~Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
o ~~Hydro-~~Quebec Interconnection	< -0.18125 Hz/sec	>0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES

[3] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.

11.3. SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. FR ~~and DDR~~ data will be provided in electronic files that are formatted in conformance with C37.111, ~~(~~IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

~~**11.4.**~~**11.5.** DDR data will be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

~~**11.5.**~~**11.6.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, upon~~within 90 calendar days of~~ the discovery of a failure of the recording capability for the SER, FR or DDR data~~, either~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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. ~~Data~~Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1,~~ Measure M1~~ for five calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, ~~Measure M5~~ for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, ~~Measure M6~~ for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, ~~Measure M7~~ for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of ~~requested data provided as per~~ Requirements R2, R3, R4, R8, R9, R10, R11, and R12, ~~Measures M2, M3, M4, M8, M9, M10, M11, and M12~~ for three calendar years.

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, ~~Measure 13~~ for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-~~-~~compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Violation Investigation~~
- ~~Self-Reporting~~
- ~~Complaints~~

~~**1.4. Additional Compliance Information**~~

~~None.~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

		days, but less than or equal to 20 calendar days.	20 calendar days, but less than or equal to 30 calendar days.	
R2	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent, but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent, but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total ~~set of~~ required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical

	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.
R4	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters~~properties~~ as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters~~properties~~ as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters~~properties~~ as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters~~properties~~ as specified in Requirement R4.
R5	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent, but less than 100 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent, but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 30 calendar	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent, but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but was late by greater than 60	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4, but

	was late by 30 calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	calendar days and less than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	was late by greater than 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical	The Transmission Owner ~~failed to~~ had~~ve~~ DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical

	quantities for each applicable BES Element ~~for all applicable BES Elements~~.	applicable BES Element ~~for all applicable BES Elements~~.	quantities for each applicable BES Element ~~for all applicable BES Elements~~.	quantities for each applicable BES Element.
R7	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is -the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element~~for all applicable BES Elements~~.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element ~~for all applicable BES Elements~~.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element ~~for all applicable BES Elements~~.	The Generator Owner ~~failed to~~ had~~ve~~ DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.
R8	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent, but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent, but less than or equal to 80 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent, but less than or equal to 70 percent of the BES Elements they own as	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

	determined in Requirement R5.	determined in Requirement R5.	determined in Requirement R5.	
R9	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent, but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent, but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent, but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 ~~failed to~~

	the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	provided the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided less than or equal to 70 percent of the data in the proper data format.
R12	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a

	provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
R13		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part

		and was late by less than or equal to 6 months.	during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-5~~4~~: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-5~~4~~: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005.

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC Oder Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14, 2023	Effective Date	April 1, 2024
5	TBD	TBD	Revised under Project 2021-04

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored Bulk Electric System (BES) buses for ~~sequence of events recording (~~SER~~)~~ and ~~Fault recording (~~FR~~)~~ data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns. Refer to section 4.2 Facilities for exclusion.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three~~-~~-phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three~~-~~-phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three~~-~~-phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete, and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three~~-~~-phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three~~-~~-phase short circuit MVA of the newly identified BES bus is within 15% of the three~~-~~-phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three-~~-~~phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other Disturbance Monitoring Equipment (DME) devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[4]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[4] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

PRC-028-1 is posted for a formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
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10-day final ballot	September 15, 2024 – September 24, 2024
Board adoption	October 15, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

2. **Number:** PRC-028-1

3. **Purpose:** To have adequate data available from inverter-based resources[1] to evaluate inverter-based resource ride-through performance during Bulk Electric System (BES) Disturbances and to provide data for inverter-based resource model validation.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Owner that owns equipment as identified in section 4.2

   4.1.2. Generator Owner that owns equipment as identified in section 4.2

   4.2. Facilities: BES inverter-based resources

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner and Generator Owner shall have circuit breaker position (open/close) sequence of event recording (SER) data for circuit breakers that it owns associated with: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Main power transformer(s)[2].

1.2. Collector bus(es), including collector feeder breakers.

1.3. Shunt static or dynamic reactive device(s).

1.4. AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to inverter-based resource.

M1. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1. Evidence may include, but is not limited to: (1) actual data recordings; or (2) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

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[1] For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource includes VSC HVDC line.

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for inverter-based resources. In case of dedicated VSC HVDC system connecting to an inverter-based resource, transformer isolating the DC-AC converter from the transmission system is considered main power transformer.

R2. Each Transmission Owner and Generator Owner shall have triggered fault recording (FR) data to determine the following electrical quantities for Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. High-side of the main power transformer FR data:

2.1.1. Phase-to-neutral voltage for each phase.

2.1.2. Each phase current and the residual or neutral current.

2.1.3. Real and reactive power expressed on a three-phase basis.

2.2. Shunt dynamic reactive device data:

2.2.1. Phase-to-neutral voltage for each phase.

2.2.2. Each phase current and the residual or neutral current.

2.2.3. Reactive power output expressed on a three-phase basis.

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R2. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R2 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. High-side of the main power transformer FR data

3.1.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.1.2. A minimum recording rate of 64 samples per cycle.

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

3.2. Shunt dynamic reactive device FR data

3.2.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.2.2. A minimum recording rate of 64 samples per cycle.

3.2.3. Trigger settings for at least the following:

3.2.3.1. Neutral (residual) overcurrent.

3.2.3.2. AC phase overvoltage and undervoltage.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R3. Evidence may include, but is not limited to: (1) actual data recordings or derivations, or (2) documents describing the device specification and device configuration or settings.

R4. Each Generator Owner and Transmission Owner shall have continuous dynamic disturbance recording (DDR) data and storage to determine the following electrical quantities for each main power transformer(s) it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. One phase-to-neutral or positive sequence voltage on high-side of the main power transformer(s).

4.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R4, Part 4.1, or the positive sequence current.

4.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to each main power transformer(s) where current measurements are required.

4.4. Frequency of any one of the voltage(s) in Requirement R4, Part 4.1.

M4. The Generator Owner or Transmission Owner has evidence (electronic or hard copy) of continuous DDR data recording and storage to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (3) station drawings.

R5. Each Transmission Owner and Generator Owner responsible for DDR data for the electrical quantities identified in Requirement R4 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Input sampling rate of at least 960 samples per second.

5.2. Output recording rate of electrical quantities of at least 60 times per second.

M5. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R5. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R5, Part 5.1; R5, Part 5.2); or (2) actual data recordings (R5, Part 5.2).

R6. Each Transmission Owner and Generator Owner shall time synchronize all SER, FR, and DDR data to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

6.2. Synchronized device clock accuracy within ± 1 milliseconds of UTC.

M6. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R7. Each Transmission Owner and Generator Owner shall provide all requested SER, FR, and DDR data to its Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within 15 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII[3] Comma Separated Value (CSV) format following Attachment 1.

7.4. FR data shall be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

7.5. DDR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

7.6. Data files shall be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M7. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R7. Evidence may include, but is not limited to: (1) actual data recordings; (2) dated transmittals to the requesting entity with formatted records; or (3) documents describing data storage capability, device specification, configuration, or settings.

R8. Each Transmission Owner and Generator Owner shall, upon the discovery of a failure of the recording capability for the SER, FR, or DDR data: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

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[3] American Standard Code for Information Exchange

M8. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R8. Evidence may include, but is not limited to: (1) dated reports of the discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated Corrective Action Plan transmittals to the Regional Entity and evidence of Corrective Action Plan implementation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner and Generator Owner shall retain evidence, as per Requirements R1 through R8, for three calendar years.

If a Transmission Owner or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the circuit breaker(s) identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the circuit breaker(s) identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the circuit breaker(s) identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the circuit breaker(s) identified in Requirement R1.
R2	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

R3	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.
R4	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.
R5	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total

	total recording parameters as specified in Requirement R5.	total recording properties as specified in Requirement R5.	percent of the total recording properties as specified in Requirement R5.	recording properties as specified in Requirement R5.
R6	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.
R7	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 15 calendar days, but less than or equal to 25 calendar days after the	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 25 calendar days, but less than or equal to 35 calendar days after the	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 35 calendar days, but less than or equal to 45 calendar days after the	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 45 calendar days after the request, unless an

	request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided less than or equal to 70 percent of the data in the proper data format.
R8	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R8 failed to restore the

			directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-028-1: Implementation Plan.

NERC Reliability Standard PRC-028-1: Technical Rationale.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011: IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

IEEE Std 2800-2022: IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.

Multiple Solar PV Disturbances in CAISO, Joint NERC and WECC Staff Report, April 2022.

NERC Reliability Standard PRC-002-5.

Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021, Joint NERC and Texas RE Event Report, September 2021.

Odessa Disturbance, Texas Event: June 4, 2022, Joint NERC and Texas RE Event Report, December 2022.

Version History

Version	Date	Action	Change Tracking
0	TBD	Developed by Project 2021-04 Drafting Team	New

Attachment 1

Sequence of Events Recording (SER) Data Format

(Requirement R7, Part 7.3)

Date, Time, Local Time Code, Plant Name, Device, State[4]

08/27/23, 23:58:57.110, -5, Plant name 1, Breaker 1, Close

08/27/23, 23:58:57.082, -5, Plant name 2, Breaker 2, Close

[4] Breaker status and any other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is acceptable.

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

PRC-028-1 is posted for a formal comment period with additional ballot.

Completed Actions	Date
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SAR posted for comment	June 14, 2021 – July 13, 2021

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Term(s):

N/A~~The terms Inverter-Based Resource (IBR) and IBR unit refers to the proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators.~~

~~As of this posting, these~~ this ~~definitions are~~is~~:~~

~~**Inverter-Based Resource**: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell.~~

~~**IBR Unit**: An individual device that uses a power electronic interface, such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connects at a single point on the collector system; or a grouping of multiple devices that uses a power electronic interface(s), such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connect together at a single point on the collector system.~~

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for ~~I~~inverter-~~B~~based ~~R~~resources

2. **Number:** PRC-028-1

3. **Purpose:** To have adequate data available from ~~I~~inverter-~~B~~based ~~R~~resources[1] ~~(IBR)~~ to evaluate ~~facilitate analysis of IBR~~inverter-based resource ride-through performance during Bulk Electric System (BES) Disturbances and to provide data for ~~IBR~~inverter-based resource model validation.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Owner that owns equipment as identified in section 4.2

   4.1.2. Generator Owner that owns equipment as identified in section 4.2

   Facilities:

   4.2. ~~The Elements associated with (1)~~ BES ~~I~~inverter-~~B~~based ~~R~~resources~~; and (2) Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV~~.

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner and Generator Owner shall have ~~sequence of event recording (SER) data for the following Elements~~ circuit breaker position (open/close) sequence of event recording (SER) data for circuit breakers that it owns associated with: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. ~~Circuit breaker position (open/close) for circuit breakers associated with the main~~ Main power transformer(s)[2].

1.2. ~~c~~Collector bus(es), including collector feeder breakers~~, and~~.

1.3. ~~s~~Shunt static or dynamic reactive device(s), including any filter banks.

[1] For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource includes VSC HVDC line.

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for ~~dispersed power producing~~inverter-based ~~resources~~resources. In case of dedicated VSC HVDC system connecting to an inverter-based resource, transformer isolating the DC-AC converter from the transmission system is considered main power transformer.

~~1.1.~~1.4. AC-DC and DC-AC converters, if any, in case of VSC HVDC line with a dedicated connection to inverter-based resources.

~~**1.2.** For IBR Units in commercial operation after [the effective date of this standard]: at least one IBR Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% of the longest collector feeder. The following data shall be recorded when triggered by ride-through operation or tripping of an IBR Unit.~~

~~**1.2.1.** All fault codes.~~

~~**1.2.2.** All fault alarms.~~

~~**1.2.3.** High and low voltage ride-through mode status.~~

~~**1.2.4.** High and low frequency ride-through mode status.~~

~~**1.3.** For IBR Units in commercial operation prior to [the effective date of this standard]: at least one IBR Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% of the longest collector feeder. The following data shall be recorded, if capable of recording, when triggered by ride-through operation or tripping of an IBR Unit.~~

~~**1.3.1.** All fault codes.~~

~~**1.3.2.** All fault alarms.~~

~~**1.3.3.** High and low voltage ride-through mode status.~~

~~High and low frequency ride-through mode status.~~

M1. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1. Evidence may include, but is not limited to: (1) actual data recordings; or (2) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R2. Each Transmission Owner and Generator Owner shall have triggered fault recording (FR) data to determine the following electrical quantities for Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. High-side of the main power transformer FR data:

2.1.1. Phase-to-neutral voltage for each phase.

2.1.2. Each phase current and the residual or neutral current.

2.1.3. Real and reactive power expressed on a three-phase basis.

~~**2.2.** IBR Unit FR data from at least one IBR Unit, per collector bus, on any of the collector feeders that is connected at a distance greater than or equal to 90% of the longest collector feeder:~~

~~**2.2.1.** Each AC phase-to-neutral or phase-to-phase voltage, as applicable, at IBR Unit terminals or on high-side of the IBR Unit transformer.~~

~~**2.2.2.** Each AC phase current and the residual or neutral current, as applicable, on IBR Unit terminals or on high-side of the IBR Unit transformer.~~

~~**2.3.**~~**2.2.** Shunt dynamic reactive device data:

~~**2.3.1.**~~**2.2.1.** Phase-to-neutral voltage for each phase.

~~**2.3.2.**~~**2.2.2.** Each phase current and the residual or neutral current.

~~**2.3.3.**~~**2.2.3.** ~~Real and r~~Reactive power output expressed on a three-phase basis.

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R2. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R2 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. High-side of the main power transformer FR data

3.1.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.1.2. A minimum recording rate of 64 samples per cycle.

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

~~**3.2.** IBR Unit level data~~

~~**3.2.1.** A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2 seconds for the same trigger point.~~

~~**3.2.2.** A minimum recording rate of 64 samples per cycle).~~

~~**3.2.3.** Trigger settings for at least the following:~~

~~**3.2.3.1.** AC Phase overvoltage and undervoltage.~~

~~**3.2.3.2.** Overfrequency and underfrequency.~~

~~**3.3.**~~**3.2.** Shunt dynamic reactive device FR data

~~3.3.1.~~3.2.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

~~3.3.2.~~3.2.2. A minimum recording rate of 64 samples per cycle.

~~3.3.3.~~3.2.3. Trigger settings for at least the following:

~~3.3.3.1.~~3.2.3.1. Neutral (residual) overcurrent.

~~3.3.3.2.~~3.2.3.2. AC phase overvoltage and undervoltage.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R3. Evidence may include, but is not limited to: (1) actual data recordings or derivations, or (2) documents describing the device specification and device configuration or settings.

R4. Each Generator Owner and Transmission Owner shall have continuous dynamic disturbance recording (DDR) data and storage to determine the following electrical quantities for each main power transformer(s) it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. One phase-to-neutral or positive sequence voltage on high-side of the main power transformer(s).

4.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R4, Part 4.1, or the positive sequence current.

4.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to each main power transformer(s) where current measurements are required.

4.4. Frequency of any one of the voltage(s) in Requirement R4, Part 4.1.

M4. The Generator Owner or Transmission Owner has evidence (electronic or hard copy) of continuous DDR data recording and storage to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (3) station drawings.

R5. Each Transmission Owner and Generator Owner responsible for DDR data for the electrical quantities identified in Requirement R4 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Input sampling rate of at least 960 samples per second.

5.2. Output recording rate of electrical quantities of at least 60 times per second.

M5. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R5. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R5, Part 5.1; R5, Part 5.2); or (2) actual data recordings (R5, Part 5.2).

R6. Each Transmission Owner and Generator Owner shall time synchronize all SER, FR, and DDR data to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

6.2. Synchronized device clock accuracy within ± 1 milliseconds of UTC.

M6. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R7. Each Transmission Owner and Generator Owner shall provide all ~~, upon~~ requested~~, all~~ SER, FR, and DDR data to its Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within ~~30~~ 15 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII[3] Comma Separated Value (CSV) format following Attachment 1.

7.4. FR ~~and DDR~~ data shall be provided ~~either in CSV format or~~ in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

~~7.4.~~7.5. DDR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

~~7.5.~~7.6. Data files shall be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M7. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R7. Evidence may include, but is not limited to: (1) actual data recordings; (2) dated transmittals to the requesting entity with formatted records; or (3) documents describing data storage capability, device specification, configuration, or settings.

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[3] American Standard Code for Information Exchange

R8. Each Transmission Owner and Generator Owner shall, upon~~within 90 calendar days of~~ the discovery of a failure of the recording capability for the SER, FR, or DDR data~~,~~ ~~either~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

M8. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R8. Evidence may include, but is not limited to: (1) dated reports of the discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated Corrective Action Plan transmittals to the Regional Entity and evidence of Corrective Action Plan implementation.

~~**R9.** Each Transmission Owner and Generator Owner of an applicable facility as specified in section A.4.2 that is in commercial operation before the effective date of this standard that is not able to install disturbance monitoring equipment in accordance with Requirements R1 through R7 in the time provided for compliance shall develop, maintain, and implement a Corrective Action Plan to provide the required capability. For each Corrective Action Plan, the Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~

~~**9.1.** Identify corrective actions and a timetable for completion.~~

~~**9.2.** Specify the circumstances causing the delay for fully or partially implementing Requirements R1 through R7 and explain how those circumstances are beyond the control of the responsible entity.~~

~~**9.3.** Identify revisions to the selected actions in Part 9.1, if any.~~

~~**9.4.** Identify updates to the timetable for implementing the selected actions in Part 9.1, if any.~~

~~**9.5.** Submit the Corrective Action Plan, and any revisions, to the Regional Entity, with a request to extend the time provided for compliance.~~

~~**M9.** The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R9. Evidence may include, but is not limited to, documentation noting the date the Corrective Action Plan was developed or revised, documentation noting the date the Corrective Action Plan was submitted to the Regional Entity with request to extend the time provided for compliance, and evidence of Corrective Action Plan implementation.~~

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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner and Generator Owner shall retain evidence, as per Requirements R1 through R8, for three calendar years.

If a Transmission Owner or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the ~~Elements (~~circuit breaker(s)~~ or IBR Units)~~ identified in Requirement R1~~Section 4.2 Facilities~~.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the ~~Elements (~~circuit breaker(s) ~~or IBR Units)~~ identified in Requirement R1~~Section 4.2 Facilities~~.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent but less than or equal to 70 percent of the ~~Elements (~~circuit breaker(s)~~ or IBR Units)~~ identified in Requirement R1~~Section 4.2 Facilities~~.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the ~~Elements (~~circuit breaker(s)~~ or IBR Units)~~ identified in Requirement R1~~Section 4.2 Facilities~~.
R2	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical

	quantities for each Element.	electrical quantities for each Element.	quantities for each Element.	quantities for each Element.
R3	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.
R4	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.
R5	The Transmission Owner or Generator Owner had DDR data that meets more	The Transmission Owner or Generator Owner had DDR data that meets more than	The Transmission Owner or Generator Owner had DDR data that meets more	The Transmission Owner or Generator Owner had DDR data that meets less

	than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	than or equal to 60 percent of the total recording properties as specified in Requirement R5.
R6	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.
R7	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than ~~30~~15 calendar days, but	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than ~~40~~25 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than ~~50~~35 calendar days, but	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 ~~failed to~~ provided the requested data more than ~~60~~45

	less than or equal to ~~40~~25 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6~~5~~ provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	than or equal to ~~50~~35 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6~~5~~ provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	less than or equal to ~~60~~45 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6~~5~~ provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6~~5~~ provided less than or equal to 70 percent of the data in the proper data format.
R8	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as

			The Transmission Owner or Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.
~~R9~~	~~The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan and submitted it to the Regional Entity, but failed to submit any revisions to the Regional Entity as required by Requirement R9.~~	~~The Transmission Owner or Generator Owner developed and implemented a Corrective Action Plan and submitted it to the Regional Entity as required by Requirement R9, but failed to maintain it.~~	~~The Transmission Owner or Generator Owner developed, maintained, and implemented a Corrective Action Plan, but failed to submit it to the Regional Entity as required by Requirement R9.~~	~~The Transmission Owner or Generator Owner failed to develop, maintain, or implement a Corrective Action Plan as required by Requirement R9.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-028-1: Implementation Plan.

NERC Reliability Standard PRC-028-1: Technical Rationale.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011: IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

IEEE Std 2800-2022: IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.

Multiple Solar PV Disturbances in CAISO, Joint NERC and WECC Staff Report, April 2022.

NERC Reliability Standard PRC-002-5.

Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021, Joint NERC and Texas RE Event Report, September 2021.

Odessa Disturbance, Texas Event: June 4, 2022, Joint NERC and Texas RE Event Report, December 2022.

Version History

Version	Date	Action	Change Tracking
0	TBD	~~Adopted by NERC Board of Trustees~~Developed by Project 2021-04 Drafting Team	New

Attachment 1

Sequence of Events Recording (SER) Data Format

(Requirement R7, Part 7.3)

Date, Time, Local Time Code, Plant Name, Device[4], State[5]

08/27/23, 23:58:57.110, -5, Plant name 1, Breaker 1, Close

08/27/23, 23:58:57.082, -5, Plant name 2, Breaker 2, Close

~~08/27/23, 23:58:47.217, -5, Plant name 1, IBR Unit 1, Open~~

~~08/27/23, 23:58:47.214, -5, Plant name 2, IBR Unit 2, Open~~

~~08/27/23, 23:58:47.217, -5, Plant name 1, IBR Unit 1, undervoltage ride-through mode~~

~~08/27/23, 23:58:47.214, -5, Plant name 2, IBR Unit 2, dc overcurrent trip~~

[4] ~~Device name may include specific names of breakers or IBR Units as appropriate.~~

[5] Breaker status and any other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is acceptable. ~~For IBR Unit level data, fault codes, alarms, change in operating mode etc. are also acceptable.~~

Implementation Plan

Project 2021-04
Reliability Standards PRC-002-5 and PRC-028-1

Applicable Standard(s)

- PRC-002-5 Disturbance Monitoring and Reporting Requirements
- PRC-028-1 Disturbance Monitoring and Reporting Requirements for inverter-based resources

Requested Retirement(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner (TO)
- Generator Owner (GO)

General Considerations

Additional time to implement Reliability Standard PRC-002-5 is not provided because the revisions are clarifying in nature to exclude inverter-based resources from PRC-002 applicability as they are included in PRC-028. The revision to PRC-002 does not require any procurement or installation of Disturbance Monitoring Equipment.

The Reliability Standard PRC-028-1 is expected to have wide ranging impact on TOs and GOs, as many existing and new facilities would be required to have Disturbance Monitoring Equipment. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities. The Implementation Plan takes into account scheduling outages needed to implement sequence of events recording, fault recording, and dynamic disturbance recording capability. An entity owning only one (1) identified inverter-based resource is allowed three (3) calendar years for implementation to accommodate normal outage schedules. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities. The Implementation Plan recognizes Federal Energy Regulatory Commission's directive to have this standard effective and enforceable before 2030.[1]

[1] See Order No. 901 at P226.

Effective Date of PRC-002-5

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-002-5 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-002-5 shall become effective 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.

Effective Date of PRC-028-1 and Phased-in Compliance Dates

The effective date for proposed Reliability Standard PRC-028-1 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard PRC-028-1

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance Date for PRC-028-1 Requirements R1-R7

For inverter-based resources in commercial operation on or before the effective date:

Entities shall comply with Requirements R1 through R7 at 50% of their inverter-based resources within three (3) calendar years of the effective date of PRC-028-1 and 100% of their inverter-based resources by January 1, 2030.

Entities that are required to monitor only one (1) inverter-based resource shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of Reliability Standard PRC-028-1.

For inverter-based resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later.

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than nine (9) months after the effective date of Reliability Standard PRC-028-1.

Process for Seeking an Extension from Compliance Dates

Each GO and TO that owns one or more applicable inverter-based resources that are in commercial operation before the effective date of Reliability Standard PRC-028-1 may seek an extension from the above-listed compliance dates if circumstances beyond its control prevent the installation of Disturbance Monitoring Equipment on one or more of its inverter-based resources.

To seek an extension, the entity shall develop and submit to its Regional Entity[2] a request for extension that contains at a minimum the following information:

1.1. Identification of the inverter-based resource(s) for which the entity seeks the extension;

1.2. A plan for installing the Disturbance Monitoring Equipment and a timetable for completion;

1.3. A description of the circumstances precluding the timely installation of Disturbance Monitoring Equipment and how those circumstances are beyond the control of the entity; and

1.4. Any other information the entity deems relevant to the Regional Entity's consideration of its request.

The entity shall provide any information requested by the Regional Entity in connection with its request, including any information specified in a supporting process document. If the request is granted, the entity shall implement the plan in accordance with the provided timetable. Should additional time be required, the entity shall submit an updated request to its Regional Entity.

Requests should be submitted as soon as the entity identifies circumstances prescribing the timely implementation of Reliability Standard PRC-028-1, but no later than three months prior to the compliance date for which the entity seeks an extension.

Retirement Date

Reliability Standard PRC-002-4 shall be retired immediately prior to the effective date of Reliability Standard PRC-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

[2] This is the Regional Entity that will receive any Corrective Action Plans developed in accordance with Requirement R8.

Implementation Plan~~ (Draft)~~

Project 2021-04
Reliability Standards PRC-002-5 and PRC-028-1

Applicable Standard(s)

- PRC-002-5 Disturbance Monitoring and Reporting Requirements
- PRC-028-1 Disturbance Monitoring and Reporting Requirements for ~~I~~inverter-~~B~~based ~~R~~resources

Requested Retirement(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner (TO)
- Generator Owner (GO)

General Considerations

Additional time to implement Reliability Standard PRC-002-5 is not provided because the revisions are clarifying in nature to exclude ~~I~~inverter-~~B~~based ~~R~~resources from PRC-002 applicability as they are included in PRC-028. The revision to PRC-002 does not require any procurement or installation of ~~d~~Disturbance ~~m~~Monitoring ~~e~~Equipment.

The Reliability Standard PRC-028-1 is expected to have wide ranging impact on TOs and GO~~o~~s as many existing and new facilities would be required to have ~~d~~Disturbance ~~m~~Monitoring ~~e~~Equipment. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities. The Implementation Plan takes into account scheduling outages needed to implement sequence of events recording, fault recording, and dynamic disturbance recording capability. An entity owning only one (1) identified ~~generating plant/Facility~~ inverter-based resource is allowed three (3) calendar years for implementation to accommodate normal outage schedules. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities. The Implementation Plan recognizes Federal Energy Regulatory Commission's directive to have this standard effective and enforceable before 2030.[1]

[1] See Order No. 901 at P226.

Effective Date of PRC-002-5

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-002-5 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-002-5 shall become effective 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.

Effective Date of PRC-028-1 and Phased-in Compliance Dates

The effective date for proposed Reliability Standard PRC-028-1 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard PRC-028-1

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance Date for PRC-028-1 Requirements R1-R7

For inverter-based resources ~~Plants/Ff~~acilities in commercial operation on or before the effective date:

Entities shall comply with Requirements R1 through R7 at 50% of their ~~generating plants/Facilitie~~inverter-based resources within three (3) calendar years of the effective date of PRC-028-1 and 100% of their ~~generating plant/Facilitie~~inverter-based resources by January 1, 2030.

Entities that are required to monitor only one (1) ~~generating plant/Facility~~inverter-based resource shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of Reliability Standard PRC-028-1.

For inverter-based resources~~facilities~~ entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later.

~~**For Plants/Facilities entering commercial operation within one year after the effective date:** Entities shall comply with Requirements R1 through R7 by the end of the first calendar year that is 12 months following the effective date of the standard.~~

~~**For Plants/Facilities entering commercial operation one year or later after the effective date:** Entities shall comply with Requirements R1 through R7 at the date of entering commercial operation.~~

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than nine (9) months after the effective date of Reliability Standard PRC-028-1.

~~Compliance Date for PRC-028-1 Requirement R9~~

~~Entities shall comply with Requirement R9, as applicable, by no later than January 1, 2029.~~

Process for Seeking an Extension from Compliance Dates

Each GO and TO that owns one or more applicable inverter-based resources that are in commercial operation before the effective date of Reliability Standard PRC-028-1 may seek an extension from the above-listed compliance dates if circumstances beyond its control prevent the installation of Disturbance Monitoring Equipment on one or more of its inverter-based resources.

To seek an extension, the entity shall develop and submit to its Regional Entity[2] a request for extension that contains at a minimum the following information:

1.1. Identification of the inverter-based resource(s) for which the entity seeks the extension;

1.2. A plan for installing the Disturbance Monitoring Equipment and a timetable for completion;

1.3. A description of the circumstances precluding the timely installation of Disturbance Monitoring Equipment and how those circumstances are beyond the control of the entity; and

1.4. Any other information the entity deems relevant to the Regional Entity's consideration of its request.

The entity shall provide any information requested by the Regional Entity in connection with its request, including any information specified in a supporting process document. If the request is

[2] This is the Regional Entity that will receive any Corrective Action Plans developed in accordance with Requirement R8.

granted, the entity shall implement the plan in accordance with the provided timetable. Should additional time be required, the entity shall submit an updated request to its Regional Entity.

Requests should be submitted as soon as the entity identifies circumstances prescribing the timely implementation of Reliability Standard PRC-028-1, but no later than three months prior to the compliance date for which the entity seeks an extension.

Retirement Date

Reliability Standard PRC-002-4 shall be retired immediately prior to the effective date of Reliability Standard PRC-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2021-04 Modifications to PRC-002 – Phase II

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-04 Modifications to PRC-002 – Phase II** by **8 p.m. Eastern, Friday, June 14, 2024.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 470-542-6882.

Background Information

This project will be completed in two phases. The first phase addressed the scope regarding notifications relative to the sequence of events recording (SER) and fault recording (FR) data, and to clearly identify the BES Element owners that need to have SER and FR data for transformers and transmission lines with the associated identified bus in the Glencoe Light and Power SAR.

The second phase will address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.

Questions

1. Do you agree with the modification in "**Applicability, Section 4.2. Facilities**" in PRC-028-1 to remove "Non-BES Inverter Based Resources …"?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with removing "**Inverter Based Resources**" and "**IBR Unit**" under Term(s) for Reliability Standards PRC-002-5 and PRC-028-1?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the standard drafting team removing Requirement R9 in Reliability Standard PRC-028-1 and adding it to the Implementation Plan since it is more like a process, not a Requirement?

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

   ☐ Yes
   ☐ No

   Comments:

5. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

   ☐ Yes
   ☐ No

   Comments:

6. Provide any additional comments for the standard drafting team to consider, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-002-5)

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 PRC-002-5. 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.

VRF Justification for PRC-002-5, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justifications for PRC-002-5, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30 calendar days.

VSL Justifications for PRC-002-5, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R2

The VRF did not change from the previously FERC approved PRC-002-4Reliability Standard.

VSL Justification for PRC-002-5, Requirement R2

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R3

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R3

VSLs for PRC-002-5, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-002-5, Requirement R3	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R4

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R4

VSLs for PRC-002-5, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.

VSL Justifications for PRC-002-5, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R5
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R6

VSLs for PRC-002-5, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities,	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities,	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities,	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total

which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-002-5, Requirement R6	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justification for PRC-002-5, Requirement R7
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R7

VSLs for PRC-002-5, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-002-5, Requirement R7	
Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R8
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R8
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R9
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R9
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R10
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R10
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R11
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R11

VSLs for PRC-002-5, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide

than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-002-5, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R11	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-002-5)

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 PRC-002-5. 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.

VRF Justification for PRC-002-5, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justifications for PRC-002-5, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent, but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent, but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent, but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR

	other owners that their BES Elements require SER or FR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	other owners that their BES Elements require SER or FR data by greater than20 calendar days, but less than or equal to 30 calendar days.	data by greater than 30 calendar days.

VSL Justifications for PRC-002-5, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-002-5, Requirement R1	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

~~**VSL Justification for PRC-002-5, Requirement R1**~~

~~The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.~~

VRF Justification for PRC-002-5, Requirement R2

The VRF did not change from the previously FERC approved PRC-002-4Reliability Standard.

VSL Justification for PRC-002-5, Requirement R2

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R3

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R3

VSLs for PRC-002-5, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified

specified electrical quantities for each BES Element.	the number of specified electrical quantities for each BES Element.	the number of specified electrical quantities for each BES Element.	electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-002-5, Requirement R3	
Violation, Not on A Cumulative Number of Violations	

VRF Justification for PRC-002-5, Requirement R4
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R4

VSLs for PRC-002-5, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R4.

VSL Justifications for PRC-002-5, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R4	
Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R5
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R6

VSLs for PRC-002-5, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-5, Requirement R6	
Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R7

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R7

VSLs for PRC-002-5, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of monitored BES

of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	Elements and the number of specified electrical quantities for each BES Element.

VSL Justifications for PRC-002-5, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-002-5, Requirement R7	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justification for PRC-002-5, Requirement R8
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R8
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R9
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R9
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R10
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R10
The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R11
The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R11

VSLs for PRC-002-5, Requirement R11			
Lower	Moderate	High	Severe

The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the requested data more than 50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 ~~failed to~~ provided the requested data more than 60 calendar days after the request, unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-002-5, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended	The proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-002-5, Requirement R11	
Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-5, Requirement R12

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VRF Justification for PRC-002-5, Requirement R12

The VRF did not change from the previously FERC approved PRC-002-4 Reliability Standard.

VSL Justification for PRC-002-5, Requirement R12

The VSL did not change from the previously FERC approved PRC-002-4 Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-028-1)

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 PRC-028-1. 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-028-1

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the circuit breaker(s) identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the circuit breaker(s) identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the circuit breaker(s) identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the circuit breaker(s) identified in Requirement R1.

VSL Justifications for PRC-028-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R1	
Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than	The Transmission Owner or Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers less than or

80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-028-1, Requirement R2	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
	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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R4	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
Guideline 2- Consistency within a Reliability Standard	and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

VSL Justifications for PRC-028-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 15 calendar days, but less than or equal to 25 calendar days after the	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 25 calendar days, but less than or	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 35 calendar days, but less than or	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 45 calendar days after the request,

request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	equal to 35 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	equal to 45 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R7	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and failed to provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement

		Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II
(PRC-028-1)

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 PRC-028-1. 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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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-028-1

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the ~~Elements (~~circuit breaker(s) ~~or IBR units)~~ identified in ~~Section 4.2 Facilities~~Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the ~~Elements (~~circuit breaker(s~~)~~) ~~or IBR units)~~ identified in ~~Section 4.2 Facilities~~Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the ~~Elements (~~circuit breaker(s) ~~or IBR units)~~ identified in ~~Section 4.2 Facilities~~Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the ~~Elements (~~circuit breaker(s) ~~or IBR units)~~ identified in ~~Section 4.2 Facilities~~Requirement R1.

VSL Justifications for PRC-028-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R1	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
	capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as	The Transmission Owner or Generator Owner had FR data as

directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	directed by Requirement R2, Parts 2.1 and 2.2 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Transmission Owner or Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R4	
for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

VSL Justifications for PRC-028-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Transmission Owner or Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Transmission Owner or Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R6	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data	The Transmission Owner or Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Part 7.2 ~~failed to~~ provided the requested data more than ~~60~~ 45 calendar days

more than ~~30~~ 15 calendar days, but less than or equal to ~~40~~ 25 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6~~5~~ provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	more than ~~40~~ 25 calendar days, but less than or equal to ~~50~~ 35 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6~~5~~ provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	more than ~~50~~ 35 calendar days, but less than or equal to ~~60~~ 45 calendar days after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6~~5~~ provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	after the request, unless an extension was granted by the requestor. OR The Transmission Owner or Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6~~5~~ provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R7	
Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less	The Transmission Owner or Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and failed to provide a Corrective Action Plan to the Regional Entity more than 120 calendar

than or equal to 100 calendar days after discovery of the failure.	than or equal to 110 calendar days after discovery of the failure.	than or equal to 120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R8	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale for Reliability Standard PRC-002-5

May 2024

PRC-002-5 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for inverter-based resources to aid with event analysis, performance monitoring, and disturbance-based inverter-based resource model validation. The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. Introducing inverter-based resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for inverter-based resources is created instead of revising the Reliability Standard PRC-002. To avoid any overlap between the Reliability Standards PRC-002 and PRC-028, BES Elements within inverter-based resources meeting the criteria set by Inclusion I4 of the BES definition are excluded from Reliability Standard PRC-002. Example in Figure 1 is provided to clarify applicability of Reliability Standards PRC-002 and PRC-028. The inverter-based resource in this example meets the criteria in inclusion I4 of the BES definition. The BES bus in substation Scott is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for BES Elements associated with the identified BES bus are per the Reliability Standard PRC-002, except for Elements associated with the inverter-based resource, i.e., circuit breaker 3. The SER, FR, and DDR data requirements for the inverter-based resource are specified in the Reliability Standard PRC-028.

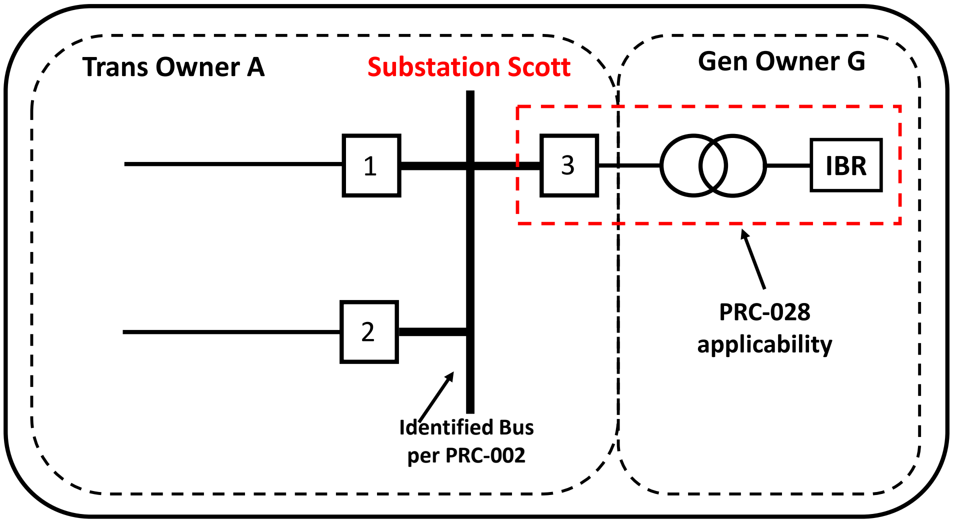

Figure 1: Example to Clarify Applicability of PRC-002 Versus PRC-028

Rationale for Requirement R1

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-5, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three-phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses, where SER and FR data is required, are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to

address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

5. Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
    a. Only tangible substation or switchyard buses are included.
    b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three-phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.

7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
    - Electrically distant BES buses or electrically distant from other DME devices
    - Voltage sensitive areas
    - Cohesive load and generation zones
    - BES buses with a relatively high number of incident Transmission circuits
    - BES buses with reactive power devices
    - Major facilities interconnecting outside the Transmission Owner's area.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B and C are identified in Step 6. The maximum three phase short circuit MVA of buses A, B, and C is 1600 MVA, 1500 MVA, and 1550 MVA, respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three phase short circuit MVA of buses A, B, and C is 1550 MVA, 1675 MVA, and 1600 MVA, respectively. The bus B is the one with highest maximum three phase short circuit MVA now. The three phase short circuit MVA of bus B is within 15% of the three phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1500 MVA, 1750 MVA and 1650 MVA respectively. The three phase short circuit MVA of bus B is greater than 15% of three phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g., synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g., combustion or steam turbine). As a result, this standard requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of “directly connected” BES Elements are notified. For the purposes of this standard, “directly connected” BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 2 and 3 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

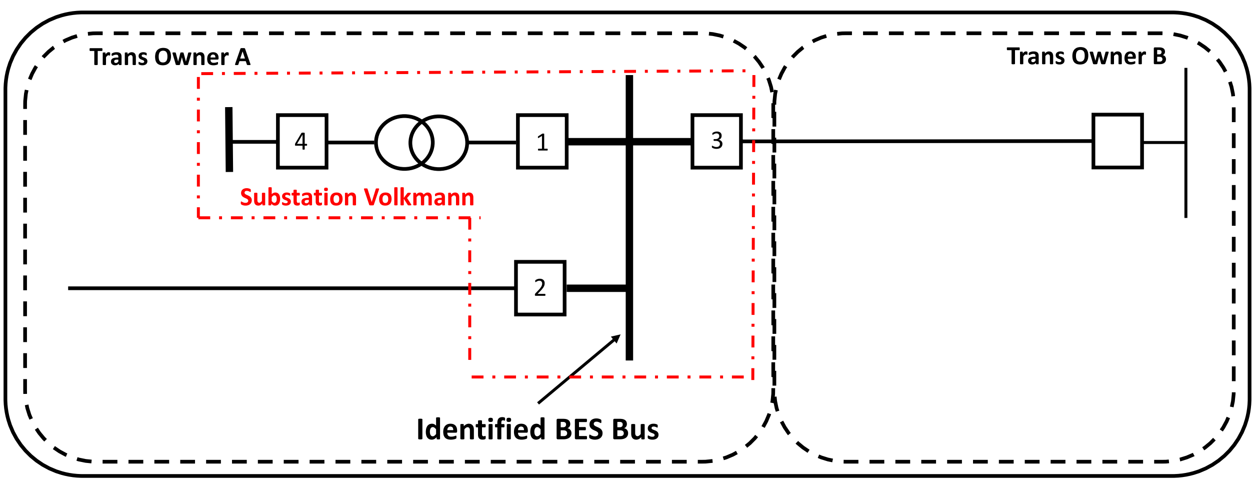

Figure 2: Straight Bus Configuration – Single Owner

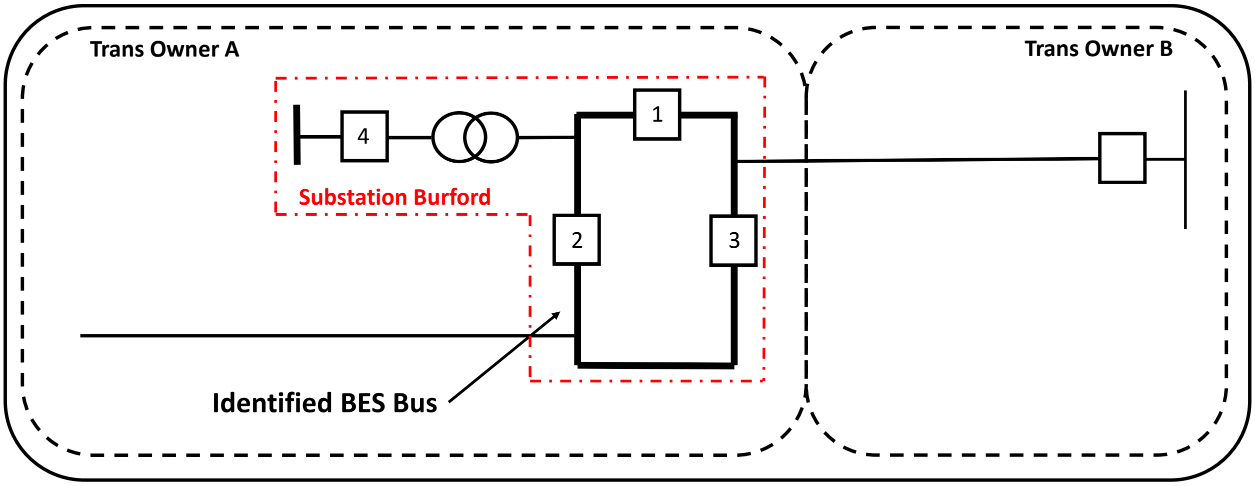

Figure 3: Ring Bus Configuration – Single Owner

Figures 4 and 5 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

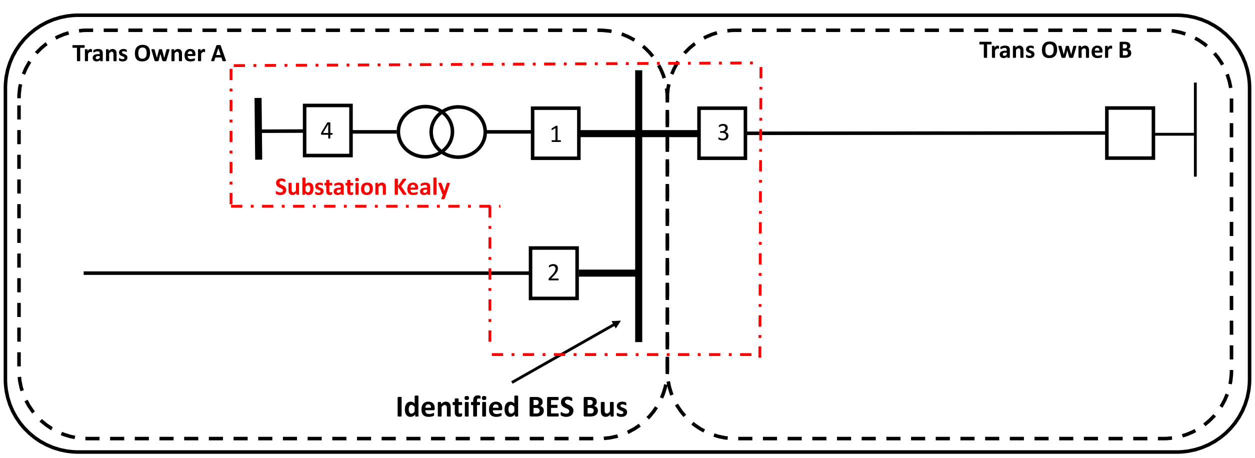

Figure 4: Straight Bus Configuration – Multiple Owners

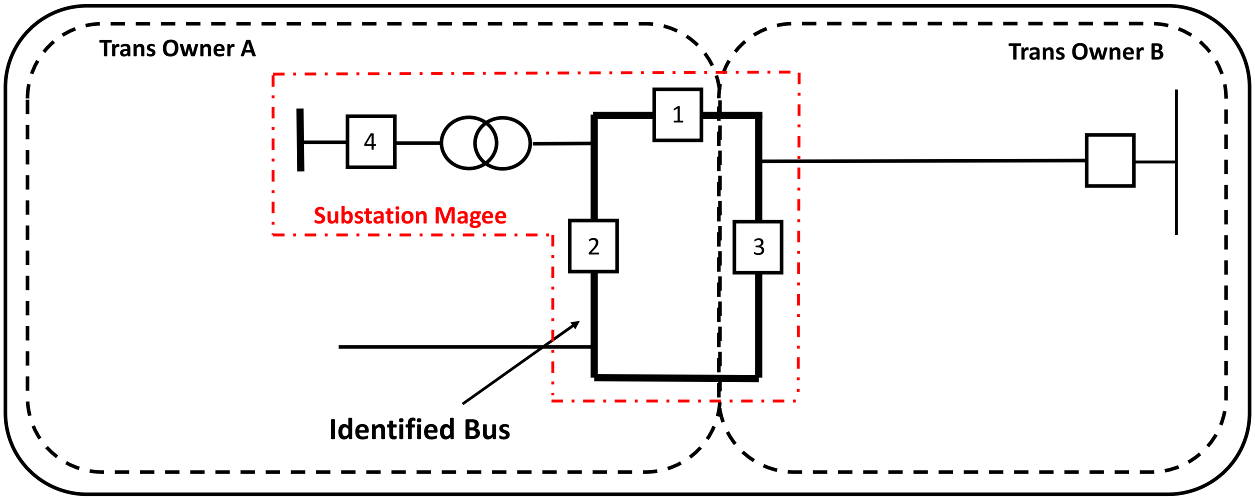

Figure 5: Ring Bus Configuration – Multiple Owners

For examples in Figures 4 and 5, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 6 shows an example with a generator interconnection. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

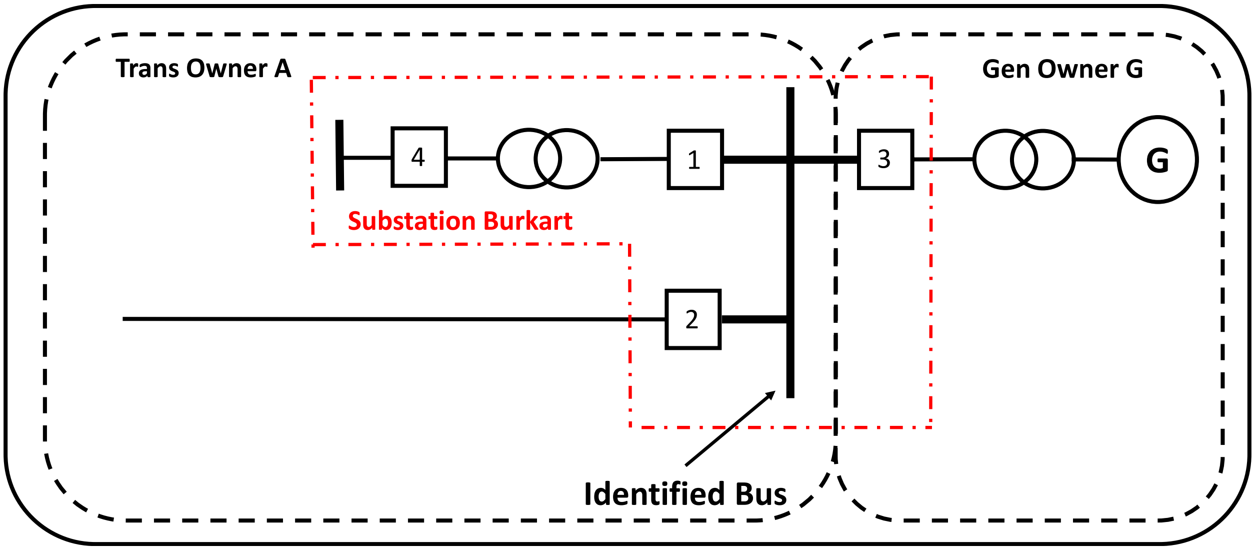

Figure 6: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 7, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

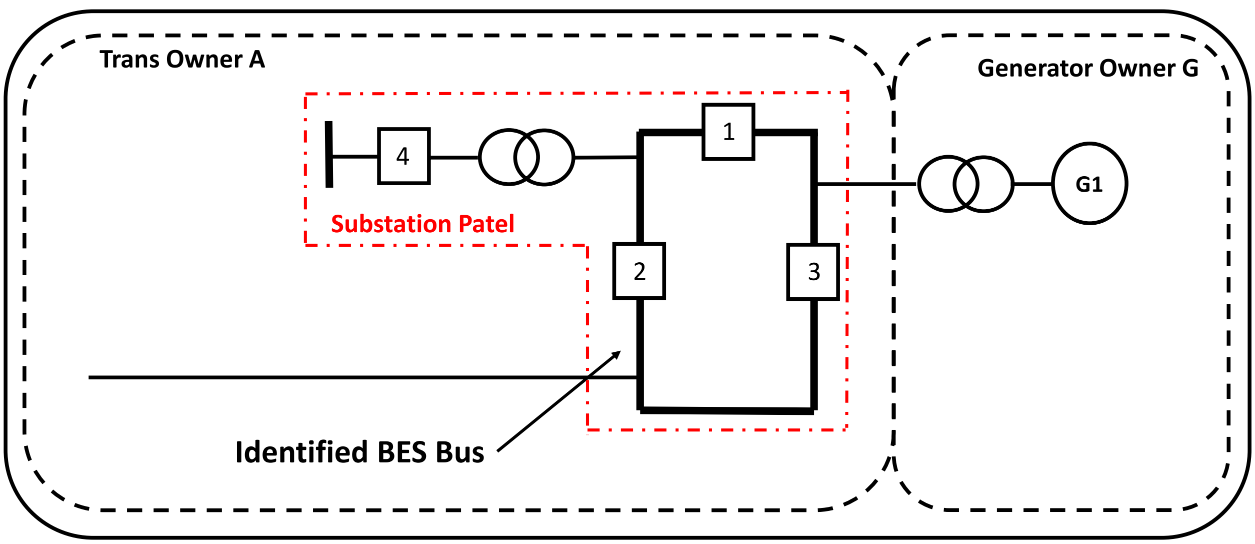

Figure 7: Generator Interconnection to Ring Bus

Figure 8 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2, and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical

bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

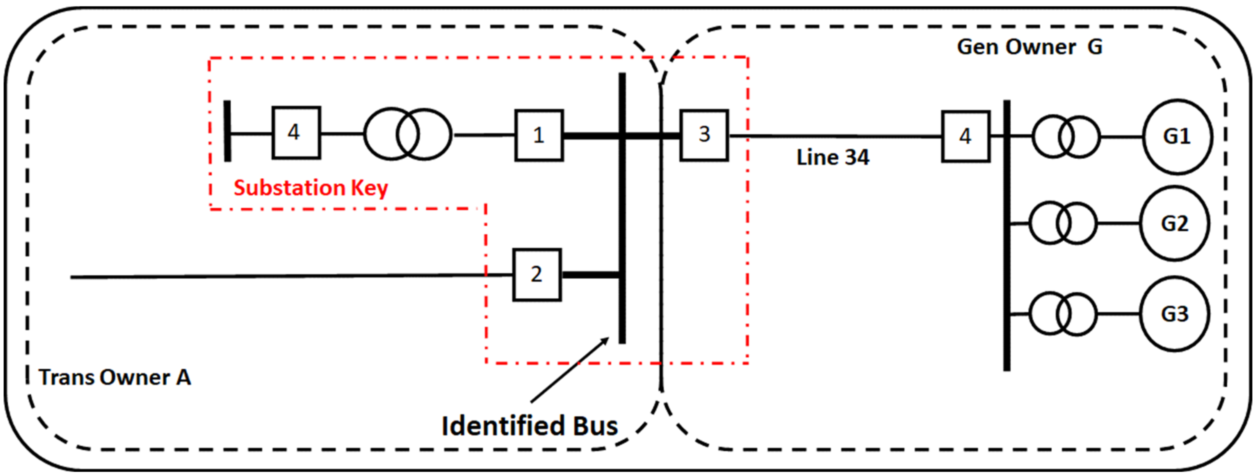

Figure 8: Generator Interconnection via Line 34

Figure 9 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3, and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

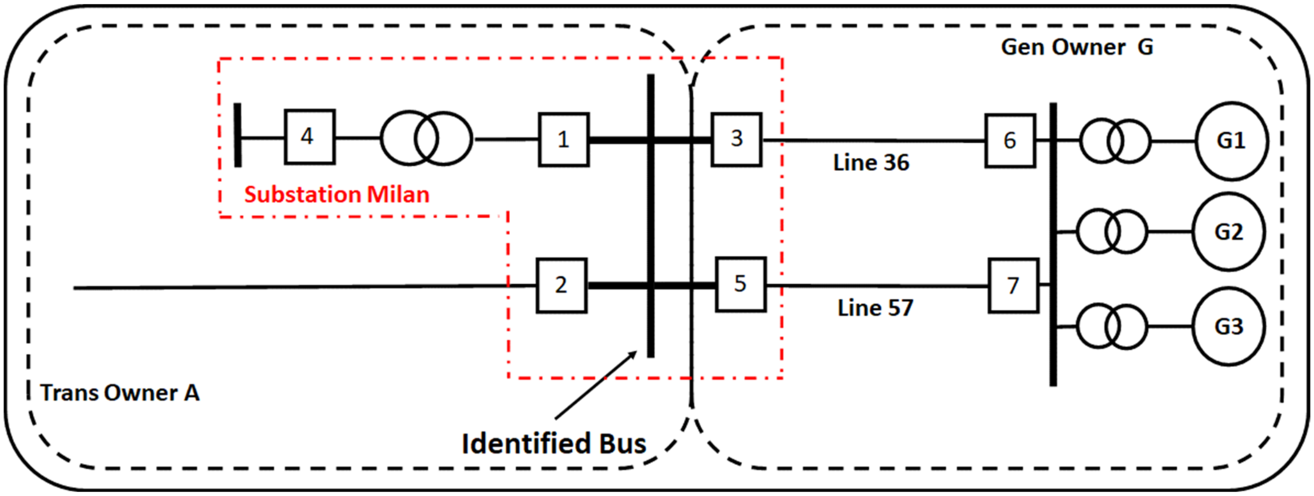

Figure 9: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification_TransmissionOwnerB

Greetings,

In accordance with NERC Standard PRC-002-5, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Rationale for Requirement R2
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element directly connected to a BES bus. Change of state of circuit breaker position and time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position.

However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Examples in Figures 10, 11, and 12 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement R3
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g., residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads 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 are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements directly connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element directly connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities, it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

Examples in Figures 10, 11, and 12 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

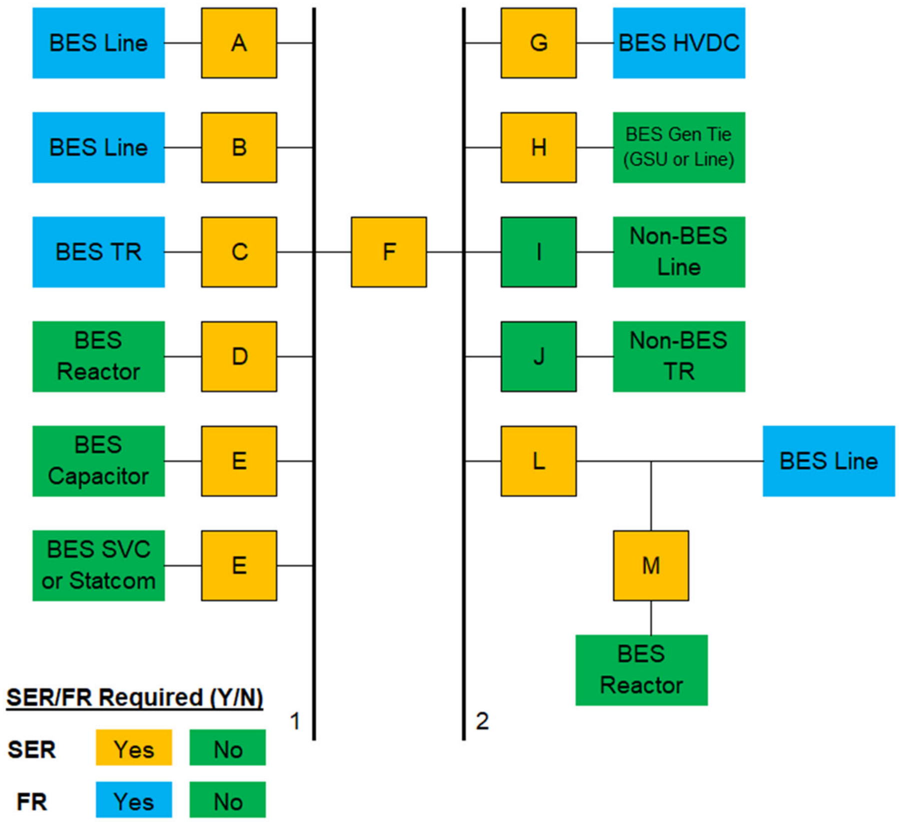

Figure 10: Straight BES Buses

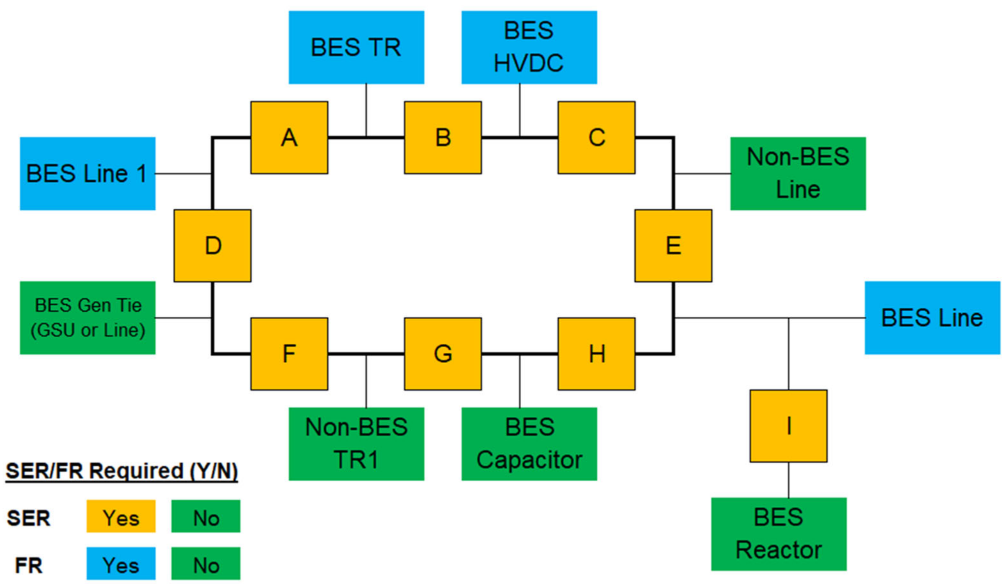

Figure 11: Ring BES Bus

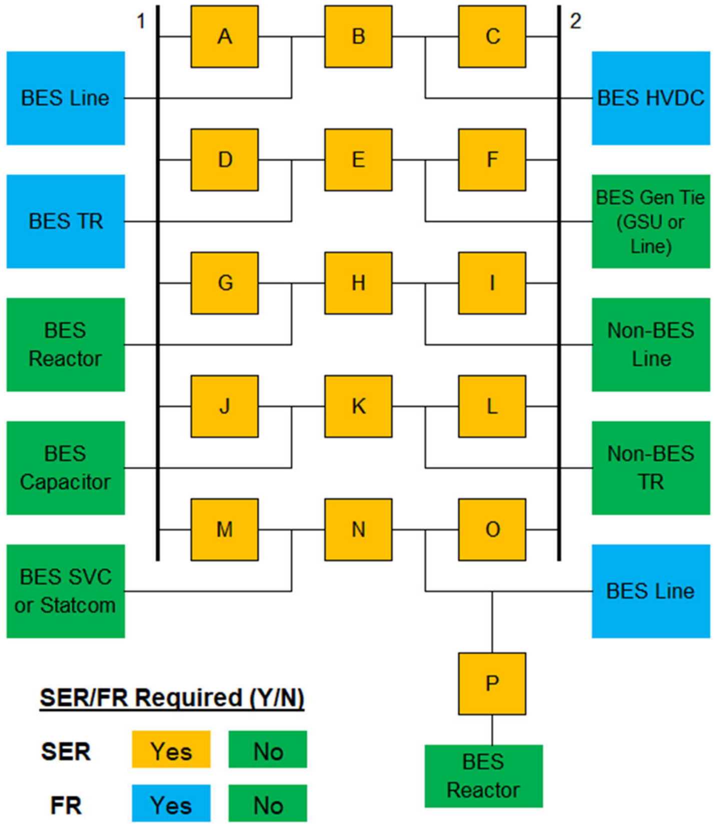

Figure 12: Breaker and Half BES Bus

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three

phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

<u>Voltage Recordings</u>
Voltages are to be recorded or accurately determined at applicable BES buses.

Rationale for Requirement R4
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data, but not capable of providing fault data in a single record with 30- contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient points on wave data for recreating accurate fault conditions.

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data, but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Rationale for Requirement R5
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for

specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data, as per Requirement R5, is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and

oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System-wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage has to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e., averages, means, and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e., units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e., the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes.

However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather, the drafting team believes this determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR, such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Rationale for Requirement R6

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral

voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three-phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Rationale for Requirement R7

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at eitherthe high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the ‘what’ of DDR, not the ‘how’. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again, it must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement R8

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post- contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Rationale for Requirement R9

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g., faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Rationale for Requirement R10

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment.

Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an

international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second level. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement R11

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30 calendar days (or the granted extension time), subject to Part 11.2, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10 calendar days inclusive of the day the data was recorded, i.e., a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.2 specifies the maximum time frame of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.1 specifies that the minimum time period of 10 calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance.

Requirement R11, Part 11.5 specifies that the DDR data shall be either in CSV format with appropriate headers or in electronic files that are formatted in conformance with IEEE C37.111. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R11, Part 11.6 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time

Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Rationale for Requirement R12

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90 calendar days (e.g., budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System.

Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90 calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to

Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Technical Rationale for Reliability Standard PRC-002-5

~~July 2022~~May 2024

PRC-002-5 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for inverter-based resources ~~(IBRs)~~ to aid with event analysis, performance monitoring, and disturbance-based ~~IBR generating facility~~ inverter-based resource model validation. The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. Introducing ~~IBR~~inverter-based resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for ~~IBR~~inverter-based resources is created instead of revising the Reliability Standard PRC-002. To avoid any overlap between the Reliability Standards PRC-002 and PRC-028, BES Elements within inverter-based resources meeting the criteria set by Inclusion I4 of the BES definition are excluded from Reliability Standard PRC-002. Example in Figure 1 is provided to clarify applicability of Reliability Standards PRC-002 and PRC-028. The ~~IBR generating facility~~ inverter-based resource in this example meets the criteria in inclusion I4 of the BES definition. The BES bus in substation Scott is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for BES Elements associated with the identified BES bus are per the Reliability Standard PRC-002 except for Elements associated with the ~~IBR generating facility~~inverter-based resource, i.e., circuit breaker 3. The SER, FR, and DDR data requirements for the ~~IBR generating facility~~inverter-based resource are specified in the Reliability Standard PRC-028.

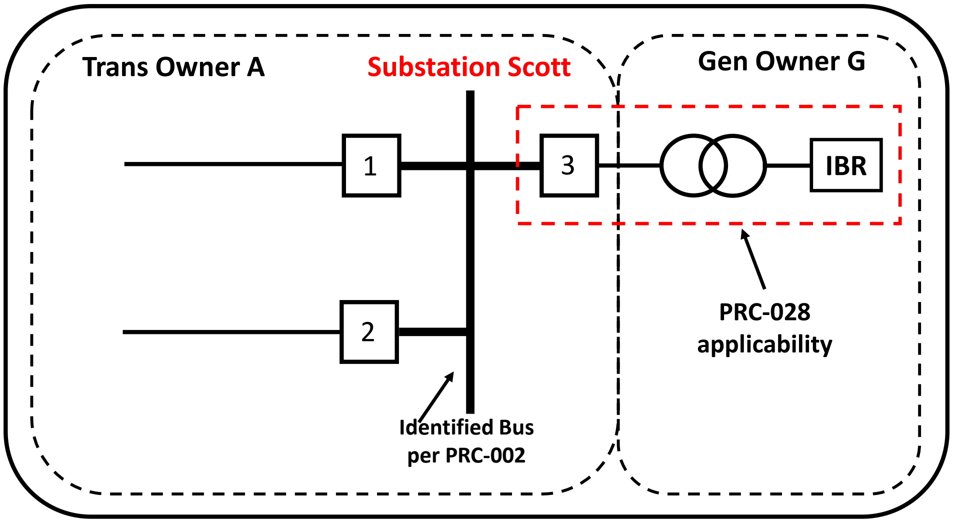

Figure 1: Example to Clarify Applicability of PRC-002 Versus PRC-028

Rationale for Requirement R1

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-5, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three-phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to

address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

5. Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
    a. Only tangible substation or switchyard buses are included.
    b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three-phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.

7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
    - Electrically distant BES buses or electrically distant from other DME devices
    - Voltage sensitive areas
    - Cohesive load and generation zones
    - BES buses with a relatively high number of incident Transmission circuits
    - BES buses with reactive power devices
    - Major facilities interconnecting outside the Transmission Owner's area.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B and C are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1600 MVA, 1500 MVA and 1550 MVA respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1550 MVA, 1675 MVA and 1600 MVA respectively. The bus B is the one with highest maximum three phase short circuit MVA now. The three phase short circuit MVA of bus B is within 15% of the three phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1500 MVA, 1750 MVA and 1650 MVA respectively. The three phase short circuit MVA of bus B is greater than 15% of three phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse

power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of "directly connected" BES Elements are notified. For the purposes of this standard, "directly connected" BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 2 and 3 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

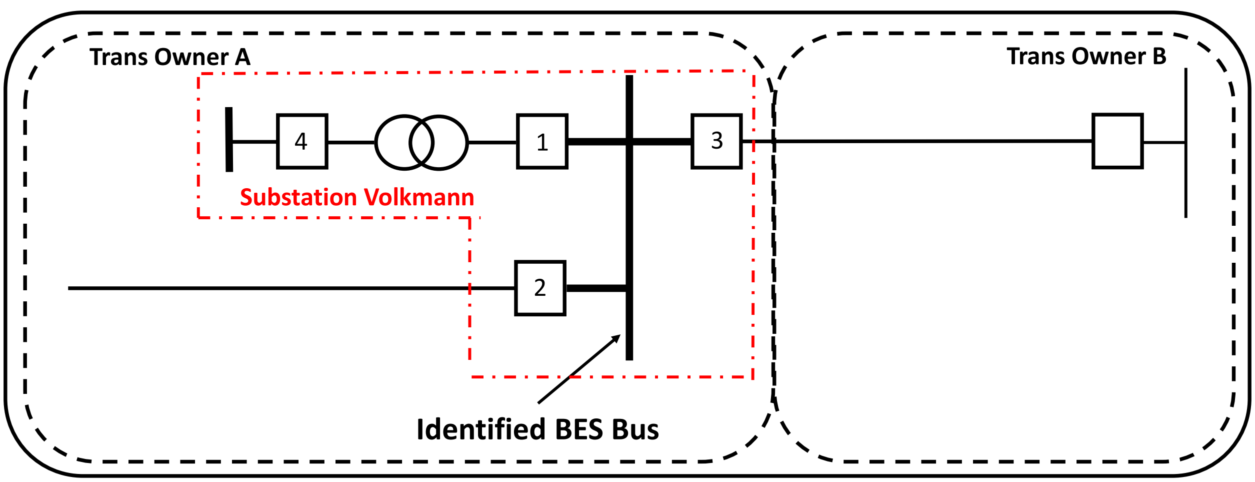

Figure 2: Straight Bus Configuration – Single Owner

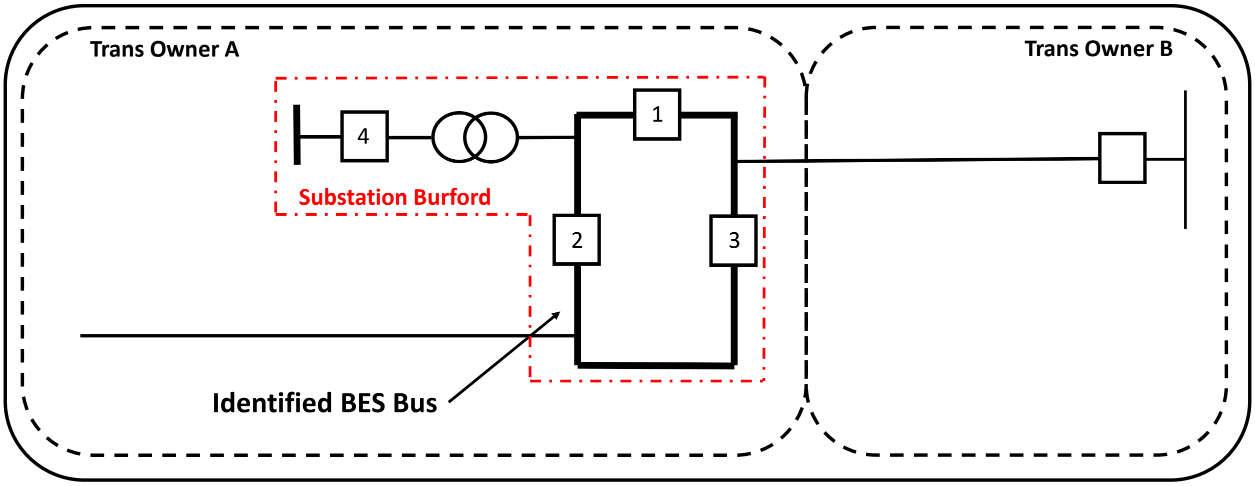

Figure 3: Ring Bus Configuration – Single Owner

Figures 4 and 5 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

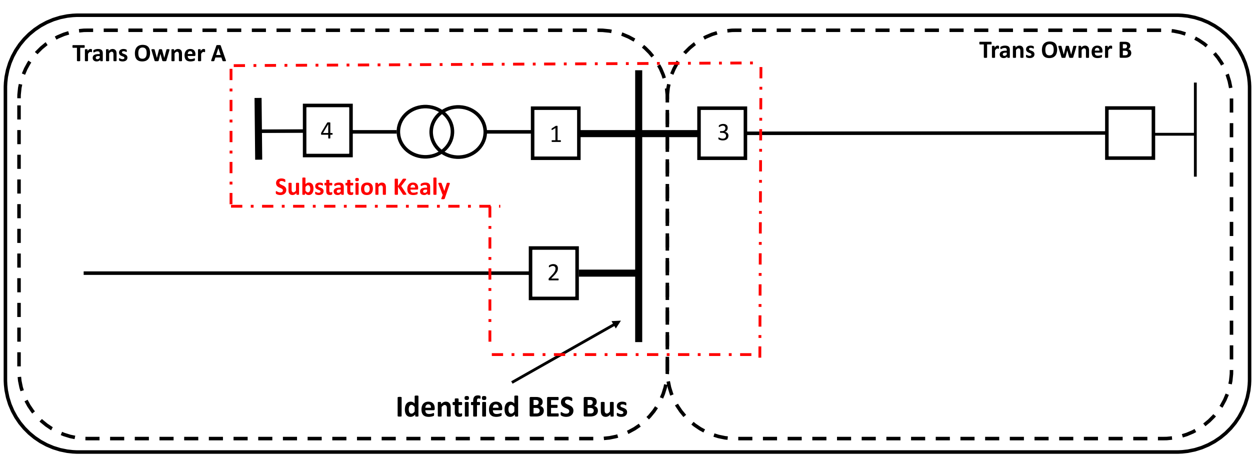

Figure 4: Straight Bus Configuration – Multiple Owners

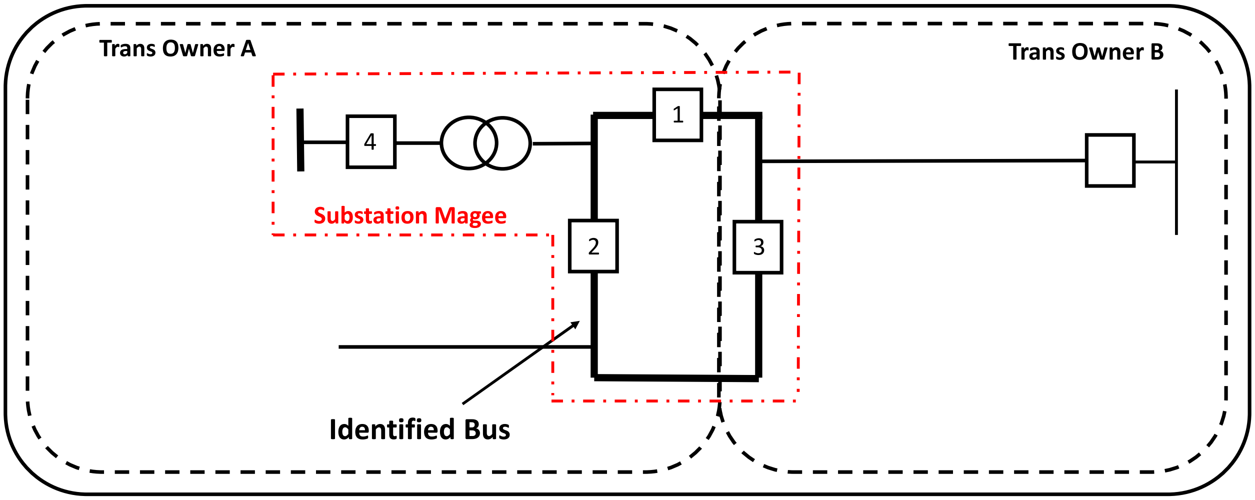

Figure 5: Ring Bus Configuration – Multiple Owners

For examples in Figures 4 and 5, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 6 shows an example with a generator interconnection. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

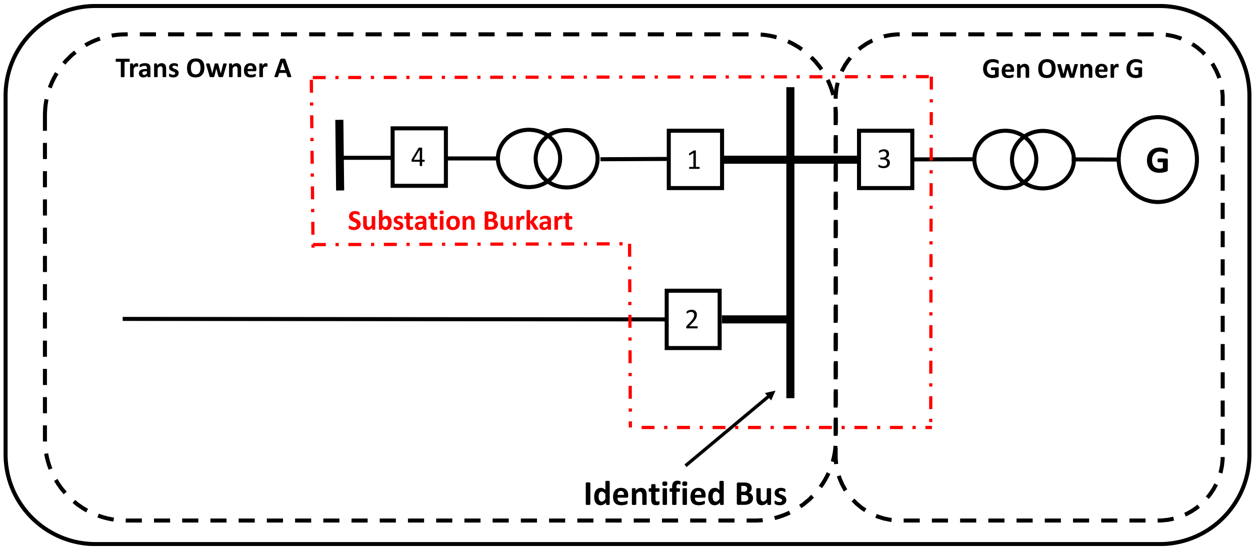

Figure 6: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 7, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

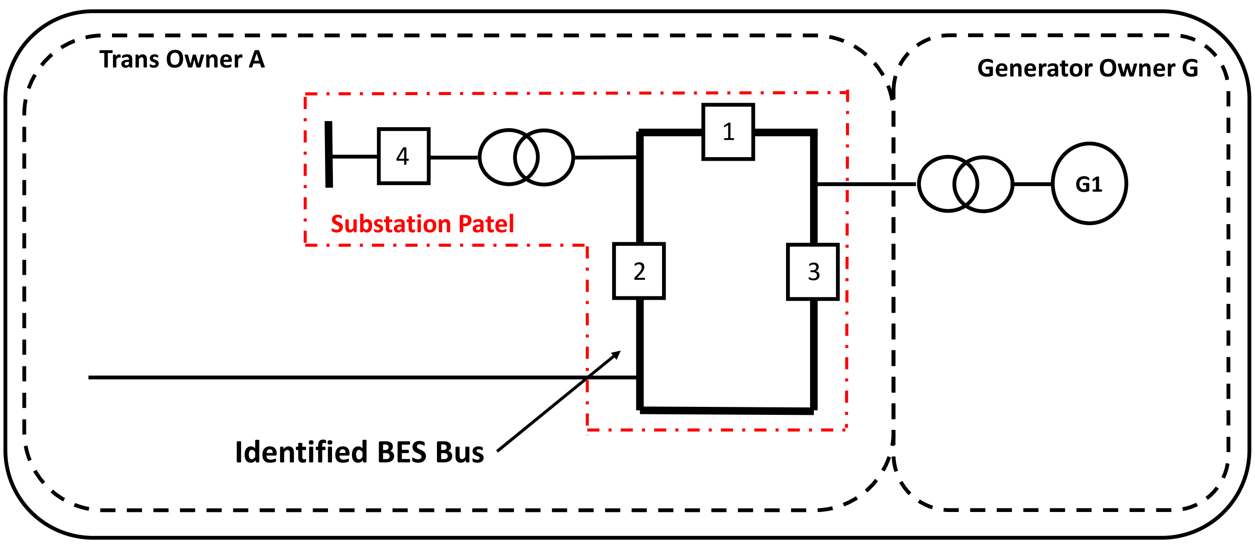

Figure 7: Generator Interconnection to Ring Bus

Figure 8 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical

bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

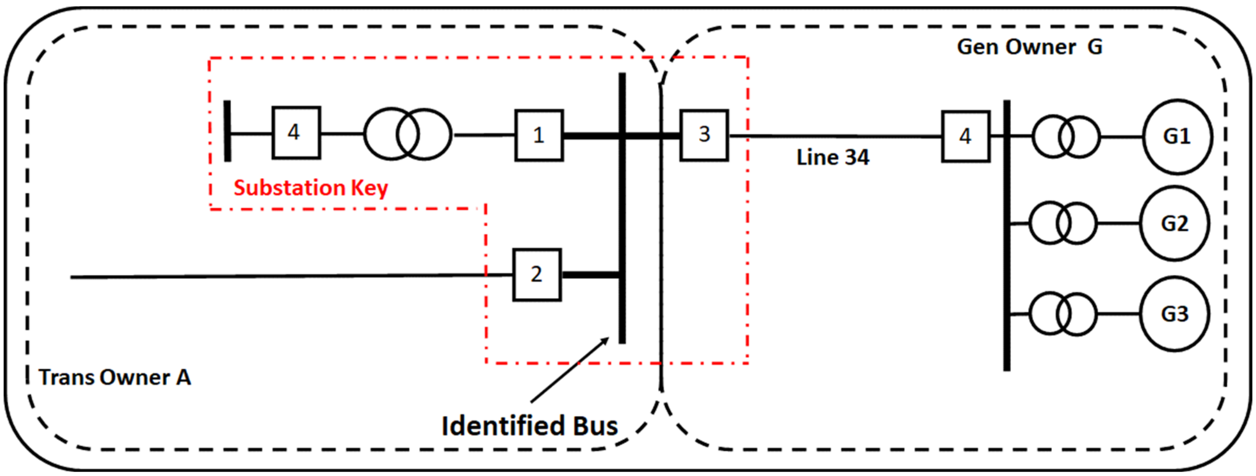

Figure 8: Generator Interconnection via Line 34

Figure 9 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3 and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

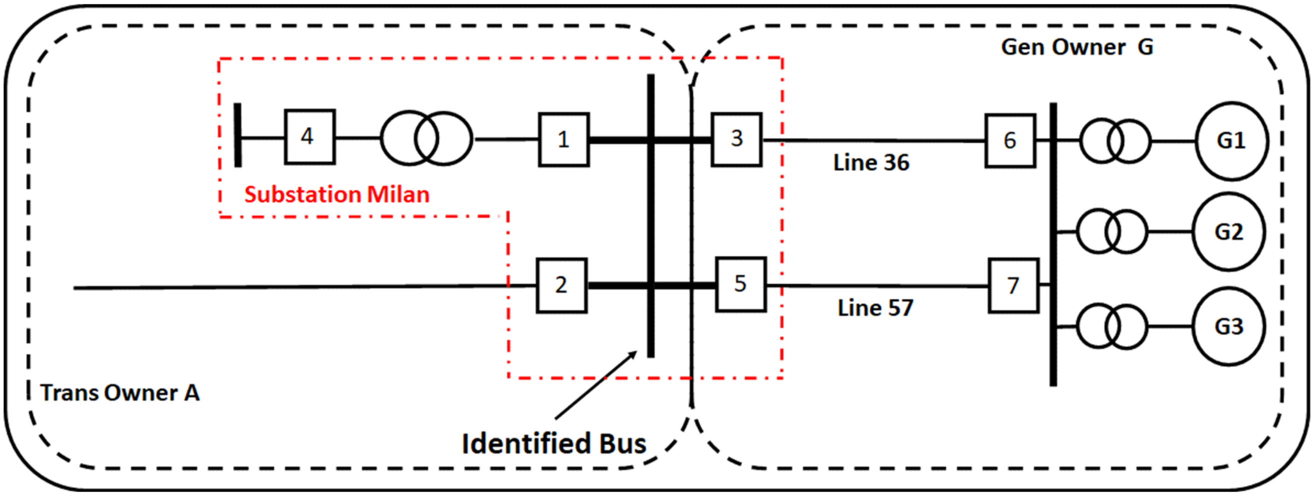

Figure 9: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification_TransmissionOwnerB

Greetings,

In accordance with NERC Standard PRC-002-5, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Rationale for Requirement R2

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element directly connected to a BES bus. Change of state of circuit breaker position and time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position.

However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Examples in Figures 10, 11 and 12 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement R3

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads 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 are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements directly connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element directly connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities, it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

Examples in Figures 10, 11 and 12 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

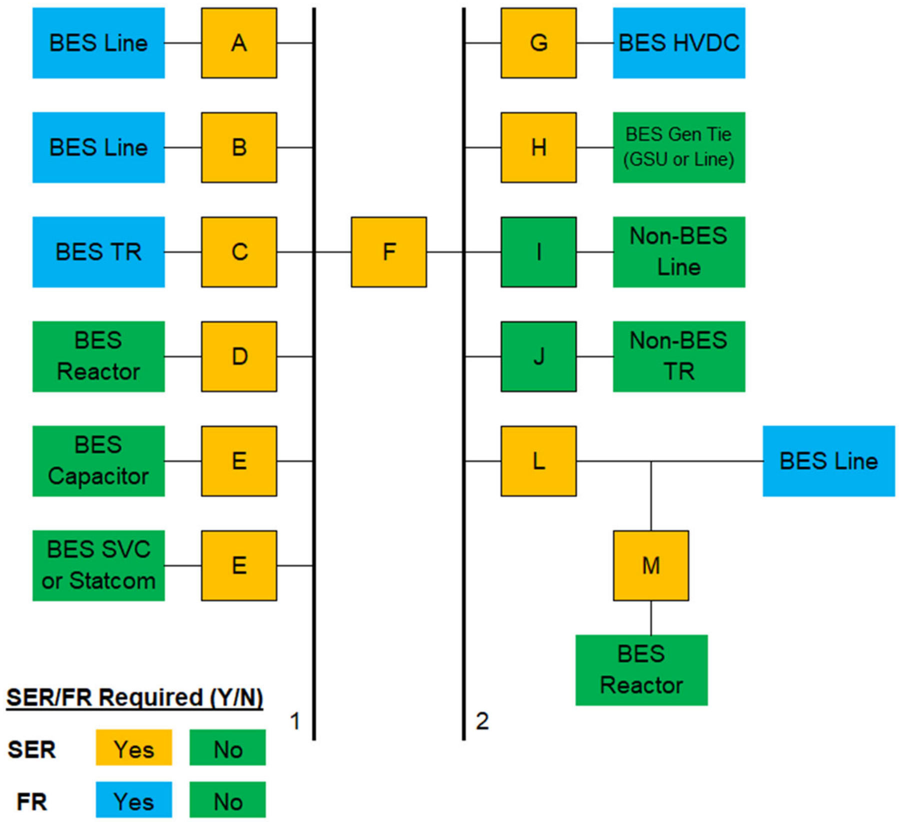

Figure 10: Straight BES Buses

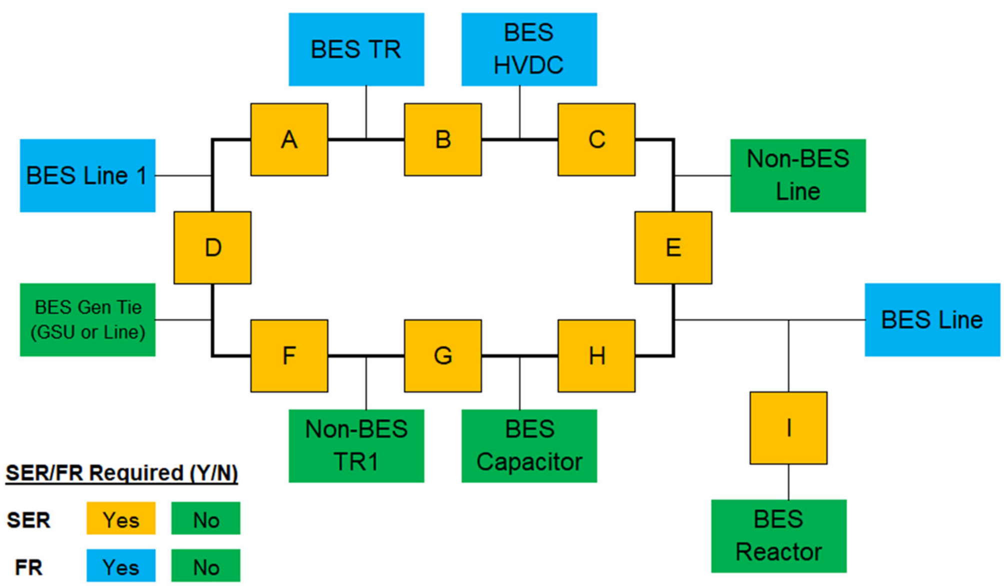

Figure 11: Ring BES Bus

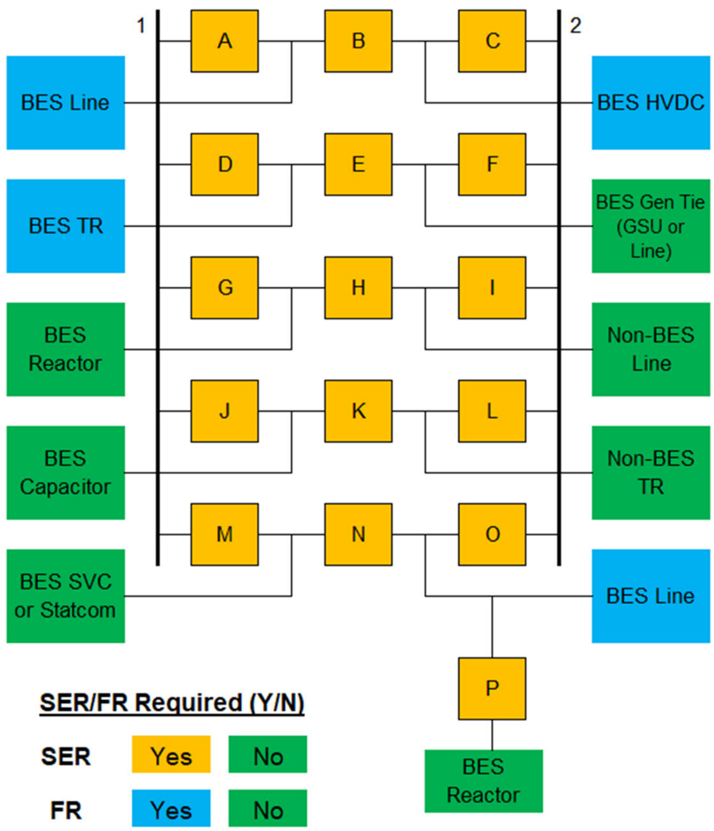

Figure 12: Breaker and Half BES Bus

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three

phase currents:

$$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings
Voltages are to be recorded or accurately determined at applicable BES buses

Rationale for Requirement R4
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30- contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Rationale for Requirement R5
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for

specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data, as per Requirement R5, is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.
DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance.
DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and

ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System-wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means, and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes.

However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather, the drafting team believes this determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR, such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Rationale for Requirement R6

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral

voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three-phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Rationale for Requirement R7
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again, it must be emphasized that the data requirements for PRC-002-5 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement R8

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post- contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Rationale for Requirement R9

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Rationale for Requirement R10
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment.
Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an

international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement R11

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30 calendar days (or the granted extension time), subject to Part 11.2, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10 calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.2 specifies the maximum time frame of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.1 specifies that the minimum time period of 10 calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR ~~and DDR~~ data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. ~~The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchrophasor data.~~

Requirement R11, Part 11.5 specifies that the DDR data shall be either in CSV format with appropriate headers or in electronic files that are formatted in conformance with IEEE C37.111. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R11, Part 11.6~~5~~ specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Rationale for Requirement R12

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90 calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System.

Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90 calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Technical Rationale for Reliability Standard PRC-028-1

2024

PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter Based Resources

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for inverter-based resources[1] to aid with event analysis, performance monitoring, and disturbance-based inverter-based resource model validation. These disturbance reports recommended to install disturbance monitoring equipment (DME) at wind and solar photovoltaic (PV) resources to ensure adequate data is available for event analysis, performance monitoring, and validating inverter-based resource models. The recommendation included plant-level high resolution oscillography data, plant SCADA data with a resolution of one second, inverter level of sequence of events recording data that include all fault codes and high resolution oscillography data. However, in a first version of this standard, recording of inverter level data is not required.

The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. The recent disturbance analyses of events involving inverter-bases resources (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have demonstrated that inverter-based resource's response to a normally cleared few cycle fault is undesirable and poses risk to system reliability. All these disturbance analyses have identified that inverter-based resources involved did not have sufficient monitoring data to understand the plants' responses. The initiating event, e.g., a normally cleared transmission fault, was not a large-scale system disturbance; however, inverter-based resource's undesirable response due to a system fault resulted in a larger system disturbance. Adequate monitoring data is required to understand inverter-based resource's performance. Most of the inverter-based resources involved in these disturbances did not have, and were not required to have adequate disturbance monitoring data. The lack of disturbance monitoring data available from these facilities led to difficulty in adequately assessing the events. Introducing inverter-based resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard

[1] For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource includes VSC HVDC line.

for monitoring requirements for inverter-based resources is created instead of revising the Reliability Standard PRC-002.

The Transmission Owners and Generator Owners, as applicable, will have the responsibility for ensuring that adequate data is available for applicable Elements at the applicable inverter-based resources. This standard requires that sequence of events recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data is available from the applicable inverter-based resources.

Rationale for Applicability Section

Functional Entities

The two functional entities that are responsible for implementing disturbance monitoring equipment and collecting recording data are: Generator Owner and Transmission Owner. The standard is only applicable to Transmission Owner in case where Transmission Owner owns equipment (e.g., circuit breaker(s), main step-up transformer, collector bus, dynamic reactive device, etc.) within the inverter-based resource.

Applicable Facilities

The BES inverter-based resources are in the scope of this standard. The inverter-based resources that connect via a dedicated voltage source converter high voltage direct current (VSC HVDC) are also in the scope of this standard.

The following Elements associated with inverter-based resources noted above are in the scope of this standard:

- Circuit breaker(s)
- Main power transformer(s)
- Collector bus
- Shunt static or dynamic reactive device(s), including any filter banks
- AC-DC and DC-AC converters, if any, in case of VSC HVDC line with a dedicated connection to inverter-based resources

The following examples are provided to clarify applicability of the PRC-028 standard.

Example 1: Applicability of PRC-028

Figure 1 shows a typical single line diagram of an inverter-based resource. The inverter-based resource is connected to the transmission system via a short tie-line. This inverter-based resource is equipped with a dynamic reactive device (e.g., synchronous condenser, static VAR compensator etc.) connected to the collector bus.

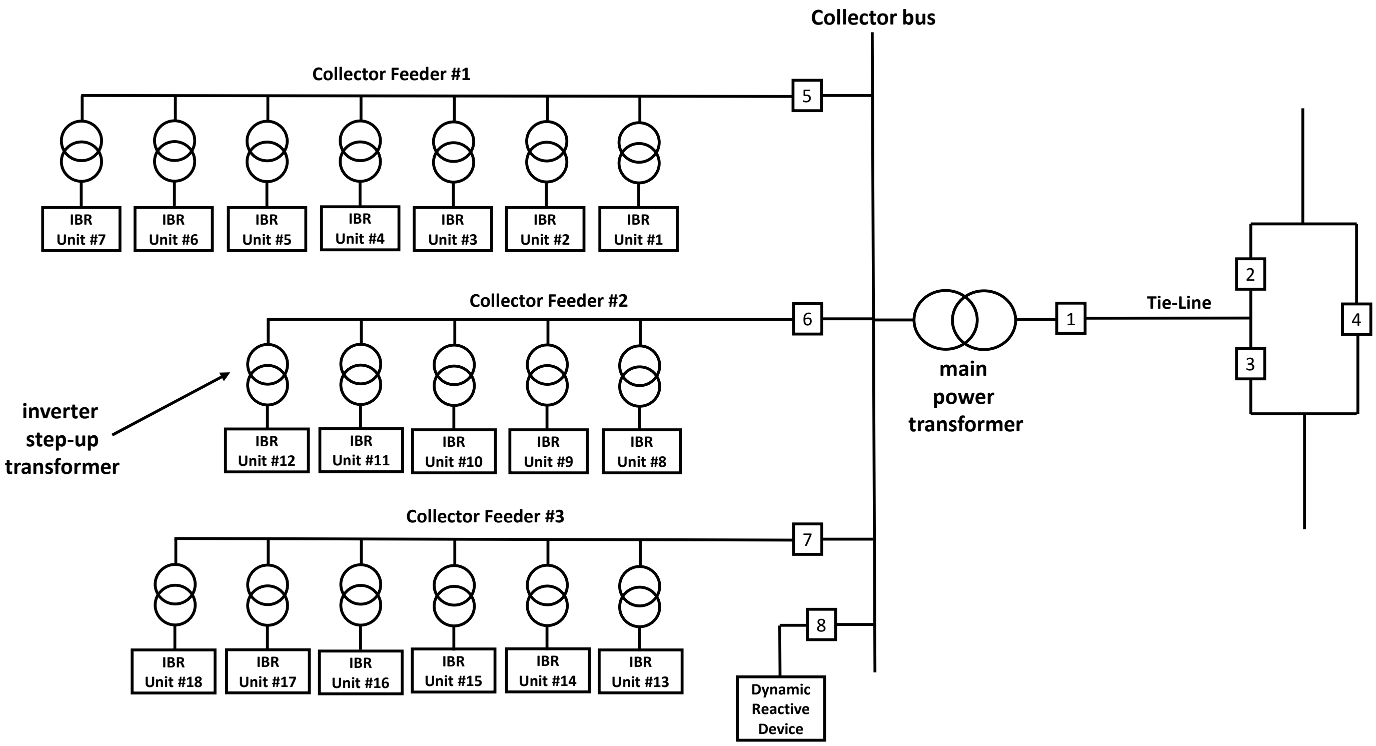

Figure 1: Typical inverter-based resource Single Line Diagram

SER Data: The SER data is required for circuits breaker 1, 5, 6, 7, and 8. Circuit breaker 1 is associated with the main power transformer. Circuit breakers 5, 6, 7, and 8 are associated with the collector bus.

FR Data: The FR data is required from high side terminals of the main power transformer. In this example, the inverter-based resource consists of only one main power transformer. If the inverter-based resource consists of more than one main power transformer, then FR data for each main power transformer is required. As the inverter-based resource is equipped with the dynamic reactive device, the FR data for it also required.

DDR Data: The DDR data is required from high side terminals of the main power transformer. If the inverter-based resource consists of more than one main power transformer, then DDR data for each main power transformer is required.

<u>Example 2: Applicability of PRC-028 (Facility with two collector buses and main power transformers)</u>
Figure 2 shows a single line diagram of an inverter-based resource with two collector buses and main power transformers. The inverter-based resource is connected to the transmission system via a short tie-line. The collector feeders #1 and #2 are connected to collector bus #1. The collector feeders #3 and #4 are connected to collector bus #2.

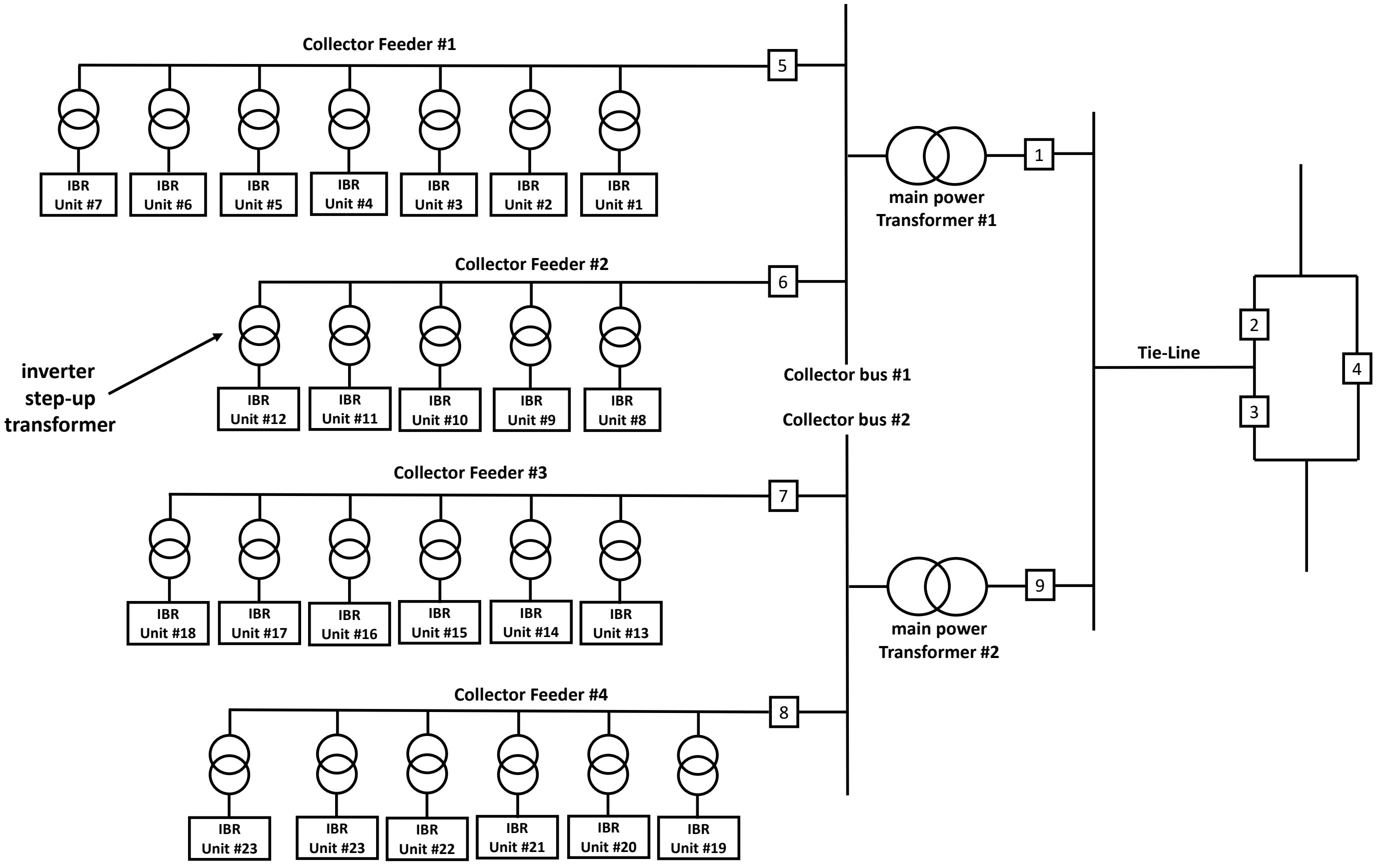

Figure 2: Typical inverter-based resource with two collector buses and main power transformers

SER Data: The SER data is required for circuits breaker 1, 5, 6, 7, 8, and 9. Circuit breakers 1 and 9 are associated with main power transformers. Circuit breakers 5, 6, 7, and 8 are associated with collector buses #1 and #2.

FR Data: The FR data is required from high side terminals of both main power transformers.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 3: Applicability of PRC-028 (VSC HVDC system with a dedicated connection to inverter-based resources)

Figure 3 shows an example of dedicated VSC HVDC system connecting the inverter-based resource. Transformers on both sides of the HVDC system are considered main power transformer.

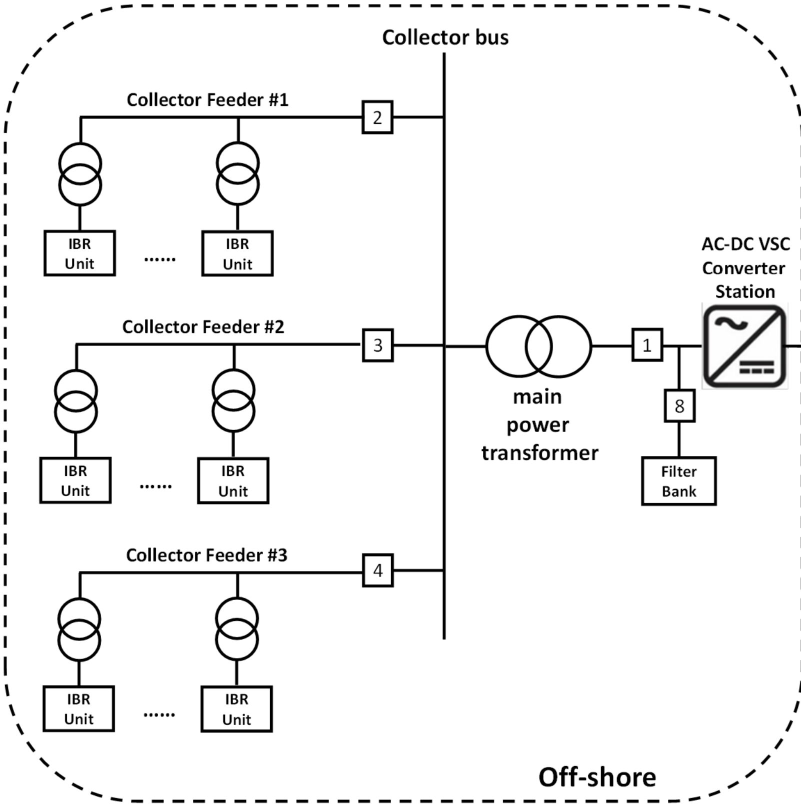

Figure 3: Typical inverter-based resource connected via dedicated VSC HVDC

SER Data: The SER data is required for circuits breaker 1, 2, 3, 4, 5, 6, 7 and 8. Circuit breakers 1 and 7 are associated with main power transformers. Circuit breakers 2, 3, and 4 are associated with the collector bus. Circuit breakers 6 and 8 are associated with filter banks and circuit breaker 5 is associated with shunt dynamic reactive device.

FR Data: The FR data is required from high side terminals of both main power transformers.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 4: Applicability of PRC-002 versus PRC-028

Figure 4 shows an example of inverter-based resource interconnection to the transmission system via Line 34. The BES bus in substation Wu is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for the identified BES bus are per the requirements in the Reliability Standard PRC-002. The Reliability Standard PRC-028 is applicable to the inverter-based resource.

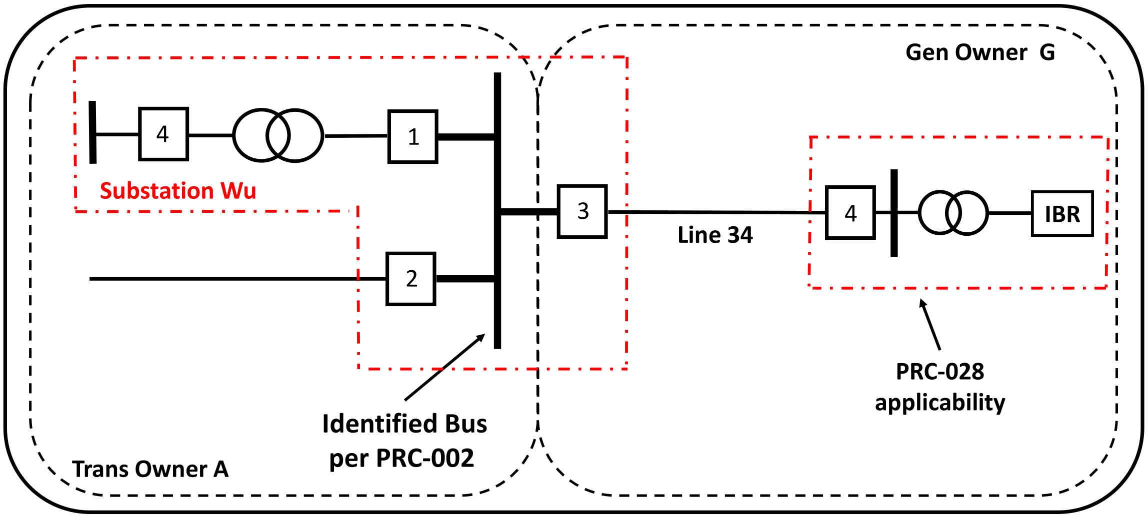

Figure 4: Inverter-based resource Interconnection – Applicability of PRC-002 versus PRC-028

Example 5: Transmission Owner owned Equipment within the inverter-based resource

Figure 5 shows an example of an inverter-based resource interconnection where Transmission Owner A owns circuit breaker 3 associated with an inverter-based resource. In this case, Transmission Owner A is responsible for SER data for circuit breaker 3. It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an inverter-based resource. However, in cases where this is true, Transmission Owner is responsible for SER, FR, and DDR data, as applicable, required by the Reliability Standard PRC-028.

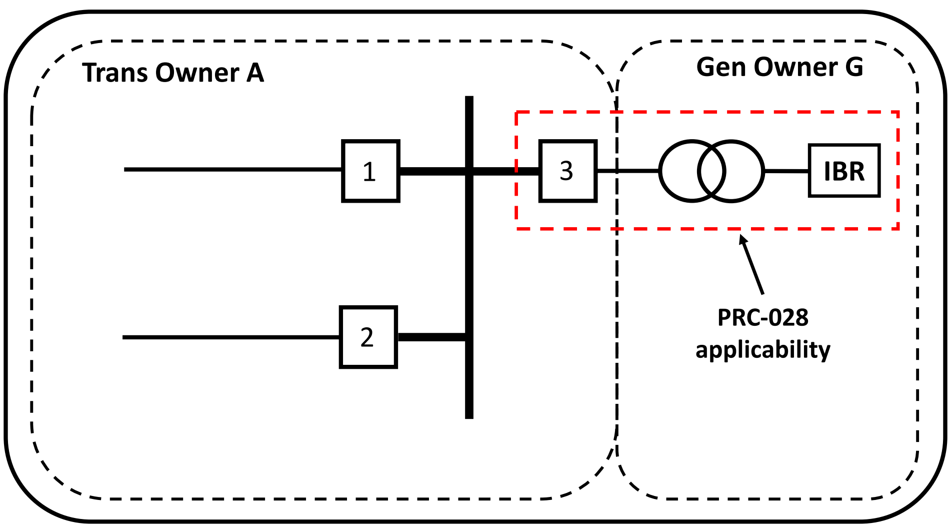

Figure 5: Transmission Owner owned Equipment within an inverter-based resource

Rationale for Requirement R1

The standard requires to capture SER data from circuit breakers within the inverter-based resource associated with:

- Main power transformer(s)

- Collector bus(es), including collector feeder breakers
- Shunt static or dynamic reactive device(s), including any filter banks
- AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to inverter-based resources.

Change of state of circuit breaker position, time stamped according to Requirement R7 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of inverter-based resource's response during a power System disturbance. Analyses of system disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations helps determine the interruption of flows during the disturbances.

Rationale for Requirement R2
The intent is to capture sufficient FR data for Elements at each inverter-based resource to analyze the overall response of the inverter-based resource to a system disturbance. Analyses of disturbances involving widespread reduction of power output from inverter-based resources in recent years has shown that expansion of monitoring at inverter-based resource sites is necessary. The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g., residual or neutral current if the phase currents are directly measured).

The plant level FR measurements, i.e., measured on high-side terminals of the main power transformer, specified in Requirement R2, Part 2.1 provide data at the inverter-based resource interconnection to the bulk power system. To cover all possible fault types, phase-to-neutral voltage recording for each phase is required to be determinable. Each phase current and residual current are required to distinguish between phase faults and ground faults. This data also facilitates determination of the fault location and cause of relay operation. The measurements of active and reactive power provide data on the overall generating facility's response to the system disturbance.

In some cases, the dynamic reactive device is used within the inverter-based resource and often connected to medium voltage collector bus. Regardless of where dynamic reactive device is connected, the output of it during system disturbances is important to understand overall performance of the plant during a disturbance. The measured or determined electrical quantities for dynamic reactive device are the same as those specified to be measured/determined from high-side of main power transformer.

Recording of Electrical Quantities
For effective fault analysis, it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation. FR also shows generator output response to a system disturbance.

Current Recordings
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle

differences of 120 degrees, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current Ir, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable Elements as outlined in Requirement R2.

Rationale for Requirement R3

Time stamped pre- and post-trigger FR data aid in the analysis of power system operations and determination if operations were as intended.

The “Odessa Disturbance” report from September 2021 recommended high resolution oscillography data at the point of interconnection. The minimum recording rate of 64 samples per cycle is specified recognizing state-of-the-art for DME including storage any storage capability limitations and provides sufficient data to recreate accurate response of the inverter-based resource to system disturbances.

Pre- and post-trigger fault data along with the SER data, all time stamped to a common clock, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Additionally, inverter-based resources employ fast acting control systems (with built in protection functions) dictating inverter-based resource’s response to system disturbance. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles. To capture the full response of inverter-based resource spread over a large geographic area, a 2 second total minimum record length synchronized to a common clock is necessary for FR data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data, but are not capable of providing fault data in a single record with 120 continuous cycles total.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R3, Part 3.1.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R3, sub-Part 3.1.3.2 specifies a phase overvoltage or undervoltage trigger during voltage ride-through events.

The triggers specified in Requirement R3, Part 3.3 for dynamic reactive device FR data are similar to ones specified in Requirement R3, Part 3.1 for plant level FR data measured or determined on high-side of the main power transformer.

Rationale for Requirement R4

Large scale system disturbances generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and inverter-based resource's response to large scale system disturbances. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event. The state-of-the-art DDR equipment is capable of continuous recording.

DDR data contains the dynamic response of the inverter-based resource to a system disturbance and is used for analyzing complex power system events. This recording is typically used to capture short-term and long-term disturbances. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

DDR is used to measure transient response to system disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage and current from the same phase or positive sequence for each applicable main power transformer for analysis. It is also sufficient to provide a single frequency for any of the provided voltages since all main power transformers within an inverter-based resource are at the same frequency. Recording of all three phases of voltage/current is not required, although this may be used to compute and record the positive sequence value(s). The electrical quantities for Real Power and Reactive Power on a three-phase basis can be measured/recorded or determined (calculated, derived, etc.).

The data requirements for PRC-028-1 are based on a system configuration assuming all normally closed circuit breakers on a BES bus are closed.

A crucial part of disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary to have DDR on high-side of the main power transformer(s) measuring the specified electrical quantities to adequately capture inverter-based resource's response.

The Requirement R4, Part 4.1 requires either one phase-to-neutral or positive sequence voltage. However, the phase-to-phase voltage recording is acceptable. Since the BES operates under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Rationale for Requirement R5

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltages and frequency. The input sampling rate specified is the same as the one specified in the Reliability Standard PRC-002.

An output recording rate of electrical quantities of at least 60 times per second refers to the recording rate of the device. Recorded measurements of at least 60 times per second provide adequate recording speed to monitor the inverter-based resource's response during power system disturbances. Since control system associated with inverter-based resources is fast acting, higher frequency recording is necessary to accurately reconstruct events. An output recording rate of 60 times per second provides this higher frequency recording while not greatly increasing data storage requirements.

Rationale for Requirement R6

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 1 millisecond accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 1 millisecond accuracy will suffice with respect to providing time synchronized data. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. Note that the recently published IEEE Std 2800 requires the DME recording plant level data be synchronized to the clock with accuracy of ± 1 microsecond accuracy; however, the accuracy requirement is set to ± 1 millisecond to strike a balance between need of accuracy and practical limitations of equipment necessary to achieve the stated accuracy.

The inverter-based resources, which are not affected by inertial time constants, make changes in power production very rapidly. To understand and analyze control decisions during system disturbances and the reasons behind them over dozens of plants requires a high level of accurate time synchronization. Following provide some examples of inverter-based resource's fast response:

- Typical 90% response to a three-phase fault is <40 ms.
- Central power plant controllers issue updated commands in as little as 40 ms upon detection of change in system conditions.
- Standard closed loop voltage control response can be <200 ms.
- Instantaneous Inverter protective trip decisions such as AC or DC overvoltage or reverse DC current can be made in less than 10 ms.

Rationale for Requirement R7

Requirement R7, Part 7.1 specifies a minimum time period of 20 calendar days inclusive of the day the data was recorded for which the data is to be retrievable. Data hold requests are usually initiated the same or next day following a major event, however, it takes a longer time to determine which data from which generating facility needs to be retrieved for event analysis. A 20 calendar day time period provides enough time for communication between various Entities regarding the event and need for data retrieval from DME at various generating facilities. The requestor of data has to be aware of 20 calendar day retrievability limit to ensure timely data hold requests. Requiring data retention for a longer period of time is expensive and unnecessary.

With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 20 days. To clarify the 20 calendar day time frame, let's assume that event occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 20 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 21, that is outside the 20 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER, FR and DDR data for generating facilities as per the applicability. To facilitate the analysis of system disturbances, it is important that the data is provided to the requestor within a reasonable time. Providing the data within 15 calendar days (or the granted extension time), subject to Requirement R7, Part 7.2, allows for reasonable time to collect the data and perform any necessary computations or formatting. An entity may request an extension of the 15 calendar days submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Disturbance analysis includes reviewing data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improve timely analysis. The formatting and naming convention requirements for SER, FR, and DDR are consistent with same requirements in the Reliability Standard PRC-002.

SER data: Requirement R7, Part 7.3 specifies a simple ASCII Comma Separated Value (CSV) format according to Attachment 1. It is necessary to establish a standard format as it allows data submitted by one entity or facility to be incorporated with same data provided by other entities or facilities to develop a detailed sequence of events timeline of a power system disturbance.

FR data: Requirement R7, Part 7.4 specifies the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the FR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources.

DDR data: Requirement R7, Part 7.5 specifies either CSV format with appropriate headers or the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the DDR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources. The 2013 revision of the IEEE C37.111 includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R7, Part 7.6 specifies the IEEE C37.232 Standard for Common Format for Naming Time Sequence Data Files (COMNAME) format for naming the SER, FR and DDR data files. The lack of a common naming practice seriously hinders the event analysis and investigation process.

Rationale for Requirement R8

The standard requires that Entity restore the recording capability for SER, FR, or DDR data within 90 calendar days of the discovery of a failure. The 90 calendar day time period permitted in this requirement strikes a balance between reasonable time needed to restore capability while ensuring that recording capability is not out of service for an extended duration. If the recording capability cannot be restored within 90 calendar days due to limitations such as budget cycle, service crews, vendors, needed outages, etc., the entity is required to submit a Corrective Action Plan for restoring the recording capability to the Regional Entity and implement it. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored Element does not constitute a failure of the disturbance monitoring capability.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale for Reliability Standard PRC-028-1

2024~~3~~

PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter Based Resources

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for ~~I~~inverter-~~B~~based ~~R~~resources[1] ~~(IBRs)~~ to aid with event analysis, performance monitoring, and disturbance-based ~~IBR~~inverter-based resource ~~generating facility~~ model validation. These disturbance reports recommended to install disturbance monitoring equipment (DME) at wind and solar photovoltaic (PV) resources to ensure adequate data is available for event analysis, performance monitoring, and validating ~~IBR~~inverter-based resource ~~generating facility~~ models. The recommendation included plant-level high resolution oscillography data, plant SCADA data with a resolution of one second, ~~sequence of events recording for all IBR Units[2]~~ inverter level of sequence of events recording data that include all fault codes~~,~~ and ~~at least one IBR Unit on each collector feeder configured to capture~~ high resolution oscillography data~~ within the IBR Unit~~. However, in a first version of this standard, recording of ~~IBR unit~~inverter level data is not required.

The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. The recent disturbance analyses of events involving ~~IBRs~~ inverter-bases resources (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have demonstrated that ~~IBR's~~inverter-based resource's response to a normally cleared few cycle fault is undesirable and poses risk to system reliability. All these disturbance analyses have identified that inverter-based resources~~IBRs~~ involved did not have sufficient monitoring data to understand the plants' responses. The initiating event, e.g., a normally cleared transmission fault, was not a large-scale system disturbance; however, ~~IBR plant's~~inverter-based resource's undesirable response due to a system fault resulted in a larger system disturbance. Adequate monitoring data is required to understand ~~IBR plant's~~ inverter-based resource's performance. Most of the ~~IBRs~~inverter-based resources involved in these disturbances did not have and

[1] For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource includes VSC HVDC line.~~Inverter-Based Resource as of 02/22/2024: A plant/facility that is connected to the electric system, consisting of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include, but are not limited to, solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell.~~ ~~**(This footnote will be removed when IBR definition is finalized)**~~

~~[2] IBR Unit as of 02/23/2024: An individual device that uses a power electronic interface, such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connects at a single point on the collector system; or a grouping of multiple devices that uses a power electronic interface(s), such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connect together at a single point on the collector system.~~ ~~**(This footnote will be removed when IBR Unit definition is finalized)**~~

were not required to have adequate disturbance monitoring data. The lack of disturbance monitoring data available from these facilities led to difficulty in adequately assessing the events. Introducing ~~IBR~~inverter-based resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for ~~IBRs~~inverter-based resources is created instead of revising the Reliability Standard PRC-002.

The Transmission Owners and Generator Owners, as applicable, will have the responsibility for ensuring that adequate data is available for applicable Elements at the applicable inverter-based resources~~IBRs generating facilities~~. This standard requires that sequence of events recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data is available from the applicable inverter-based resources~~IBRs generating facilities~~.

Rationale for Applicability Section

Functional Entities

The two functional entities that are responsible for implementing disturbance monitoring equipment and collecting recording data are: Generator Owner and Transmission Owner. The standard is only applicable to Transmission Owner in case where Transmission Owner owns equipment (e.g., circuit breaker(s), main step-up transformer, collector bus, dynamic reactive device, etc.) within the ~~IBR Plant~~inverter-based resource.

Applicable Facilities

The BES ~~I~~inverter-~~B~~based ~~R~~resources ~~and Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV~~ are in the scope of this standard.

~~Order No. 901 directed NERC to develop Reliability Standards "to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment." Order No. 901 at P 85. FERC continued, "We further agree with the findings in NERC reports (e.g., a lack of high-speed data captured at the IBR or plant-level controller and low-resolution time stamping of inverter sequence of event recorder information has hindered event analysis) and direct NERC through its standard development process to address these findings."~~

~~In distinguishing among the different types of IBRs and their registration status that must be covered by the standards, FERC stated: "Where necessary to describe our directives, however, we differentiate between IBRs registered with NERC (or which will be registered pursuant to the Commission's directives in *Registration of Inverter-based Resources*, 181 FERC ¶ 61,124 (2022) (IBR Registration Order)) and therefore~~

~~subject to the Reliability Standards (i.e., registered IBR), IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards (i.e., unregistered IBRs), and IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk-Power System (i.e., IBR-DER)." Order No. 901 at n. 14.~~

~~In proposed PRC-028-1, the standard drafting team includes both categories of generation that would be registered under proposed changes to NERC Rules of Procedure consistent with Order No. 901. In February 2024, the NERC Board of Trustees approved revisions to the Rules of Procedure to expand the Generator Owners and Generator Operators registered with NERC for compliance purposes. In addition to owners and operators of generating Facilities, NERC will register owners and operators of sub-BES IBRs meeting the following criteria: non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. More information on these changes, which are pending FERC approval, are available at: https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board%20Open%20 Agenda%20Package%20-%20February%2022%202024_ATTENDEE.pdf [nerc.com]~~

~~The standard drafting team understands that NERC will initiate a separate *Glossary* revision effort to revise the definition of Generator Owner and Generator Operator consistent with the proposed Rules of Procedure definitions for registration. This effort will complete well in advance of the team's proposed [X] year implementation plan for Reliability Standard PRC-028-1.~~

The following Elements associated with ~~I~~inverter-~~B~~based ~~R~~resources noted above are in the scope of this standard:

- Circuit breaker(s)
- Main power transformer(s)
- Collector bus
- Shunt static or dynamic reactive device(s), including any filter banks
- AC-DC and DC-AC converters, if any, in case of VSC HVDC line with a dedicated connection to inverter-based resources
  - ~~At least one IBR Unit on any of the collector feeders that is connected at a distance ≥ 90% of the longest collector feeder from the collector bus~~

The following examples are provided to clarify applicability of the PRC-028 standard.

Example 1: Applicability of PRC-028

Figure 1 shows a typical single line diagram of an inverter-based resource~~IBR generating facility~~. The ~~IBR~~inverter-based resource ~~generating facility~~ is connected to the transmission system via a short tie-line. ~~The length of collector feeder #1, #2, and #3 is 3000 ft, 2500 ft, and 2800 ft respectively. IBR Units #6 and~~

~~#7 are connected to collector feeder #1 at 2800 ft and 3000 ft distance from the collector bus respectively. IBR Unit #18 is connected to collector feeder #3 at 2800 ft distance from the collector bus. In other words, these IBR Units #6, #7 and #18 are connected at a distance ≥ 90% of the longest collector feeder from the collector bus.~~ This ~~IBR~~inverter-based resource ~~generating facility~~ is equipped with a dynamic reactive device (e.g., synchronous condenser, static VAR compensator etc.) connected to the collector bus.

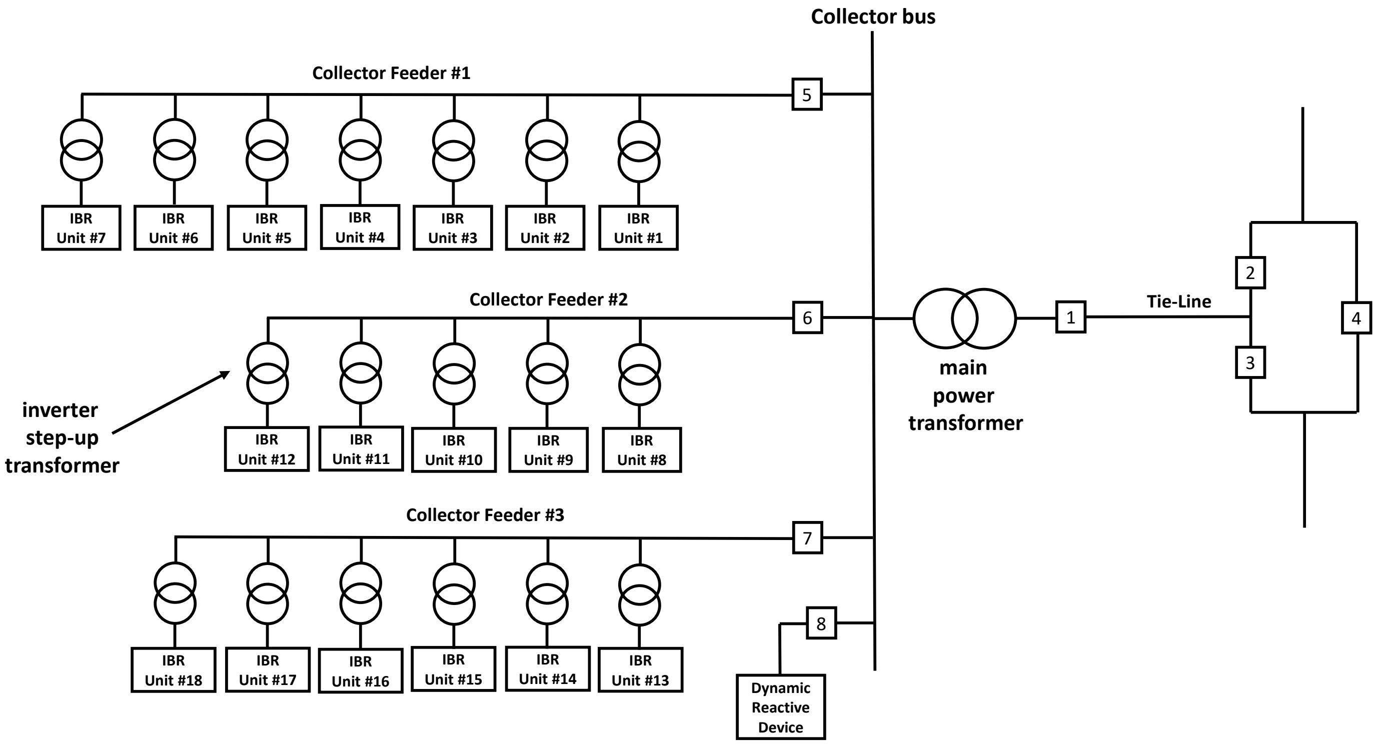

Figure 1: Typical ~~IBR~~inverter-based resource ~~Generating Facility~~ Single Line Diagram

SER Data: The SER data is required for circuits breaker 1, 5, 6, 7, and 8. Circuit breaker 1 is associated with the main power transformer. Circuit breakers 5, 6, 7, and 8 are associated with the collector bus. ~~The SER data for IBR Unit #6, #7, or #18 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus.~~

FR Data: The FR data is required from high side terminals of the main power transformer. In this example, the ~~IBR plant~~inverter-based resource consists of only one main power transformer. If the inverter-based resource~~IBR plant~~ consists of more than one main power transformer, then FR data for each main power transformer is required. ~~The FR data for IBR Unit #6, #7, or #18 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus.~~ As the inverter-based resource~~IBR plant~~ is equipped with the dynamic reactive device, the FR data for it also required.

DDR Data: The DDR data is required from high side terminals of the main power transformer. If the inverter-based resource~~IBR plant~~ consists of more than one main power transformer, then DDR data for each main power transformer is required. ~~The DDR data from individual IBR Units is not required.~~

Example 2: Applicability of PRC-028 (Facility with two collector buses and main power transformers)

Figure 2 shows a single line diagram of an inverter-based resource~~IBR generating facility~~ with two collector buses and main power transformers. The inverter-based resource~~IBR generating facility~~ is connected to the transmission system via a short tie-line. The collector feeders #1 and #2 are connected to collector bus #1. The collector feeders #3 and #4 are connected to collector bus #2. ~~The length of collector feeder #1, #2, #3, and #4 is 3000 ft, 2500 ft, 2800 ft, and 2600 ft respectively. The collector feeder #1 is the longer of two collector feeders connected to collector bus #1. IBR Units #6 and #7 are connected to collector feeder #1 at 2800 ft and 3000 ft distance from the collector bus #1 respectively. IBR Unit #12 is connected to collector feeder #2 at 2500 ft from the collector bus #1. The IBR Units #6 and #7 are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #1. The collector feeder #3 is the longer of two collector feeders connected to collector bus #2. IBR Units #17 and #18 are connected to collector feeder #3 at 2600 ft and 2800 ft distance from the collector bus #2 respectively. IBR Unit #23 is connected to collector feeder #4 at 2600 ft from the collector bus #2. The IBR Units #17, #18, and #23 are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #2.~~

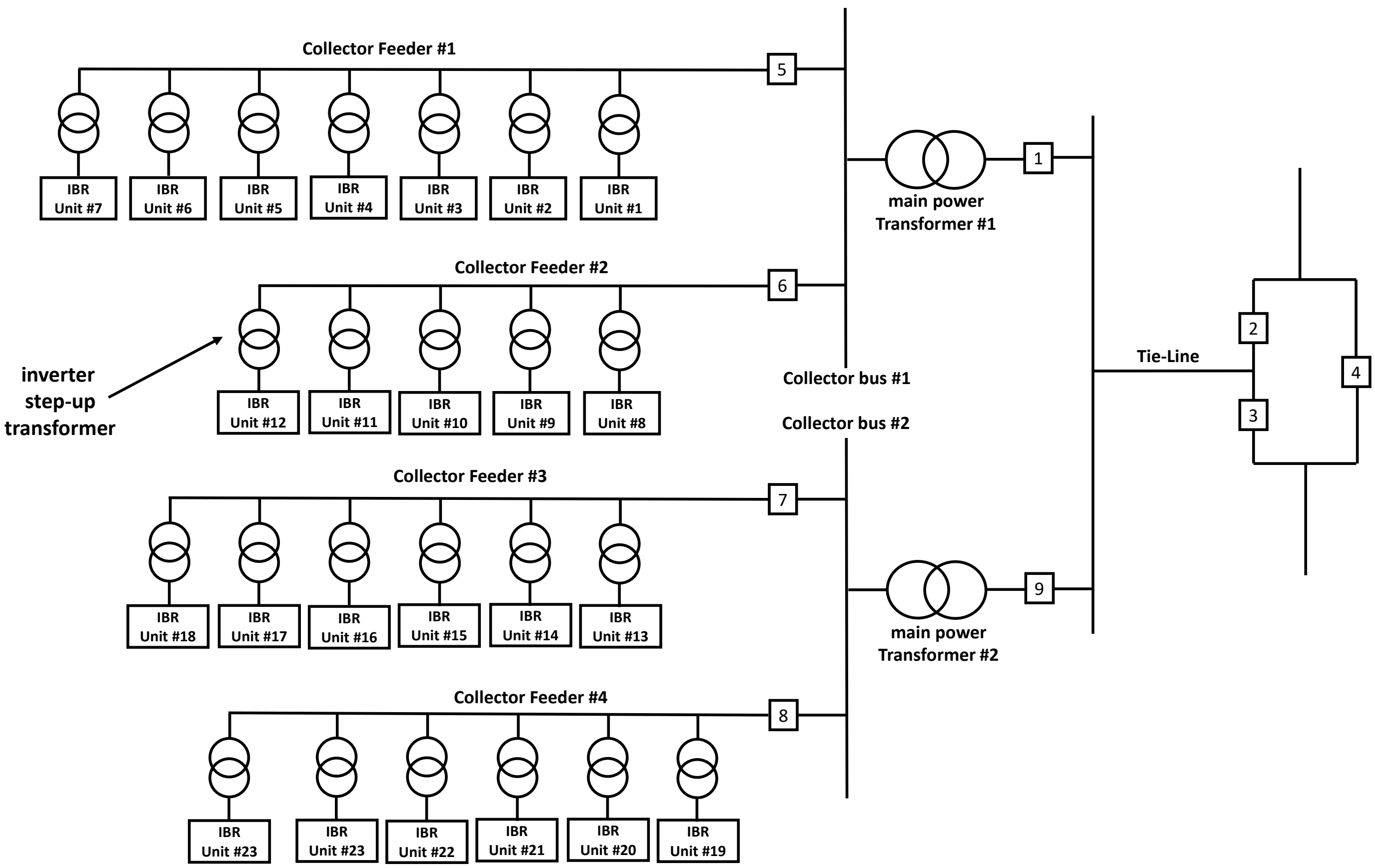

Figure 2: Typical inverter-based resource~~IBR Generating Facility~~ with two collector buses and main power transformers

SER Data: The SER data is required for circuits breaker 1, 5, 6, 7, 8 and 9. Circuit breakers 1 and 9 are associated with main power transformers. Circuit breakers 5, 6, 7, and 8 are associated with collector buses #1 and #2. ~~The SER data for IBR Unit #6 or #7 is required as these are connected at a distance ≥ 90% of the~~

~~longest collector feeder from the collector bus #1. The SER data for IBR Unit #17, #18, or #23 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #2.~~

FR Data: The FR data is required from high side terminals of both main power transformers. ~~The SER data for IBR Unit #6 or #7 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #1. The SER data for IBR Unit #17, #18, or #23 is required as these are connected at a distance ≥ 90% of the longest collector feeder from the collector bus #2.~~

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 3: Applicability of PRC-028 (VSC HVDC system with a dedicated connection to inverter-based resources)

Figure 3 shows an example of dedicated VSC HVDC system connecting the inverter-based resource. Transformers on both sides of the HVDC system are considered main power transformer.

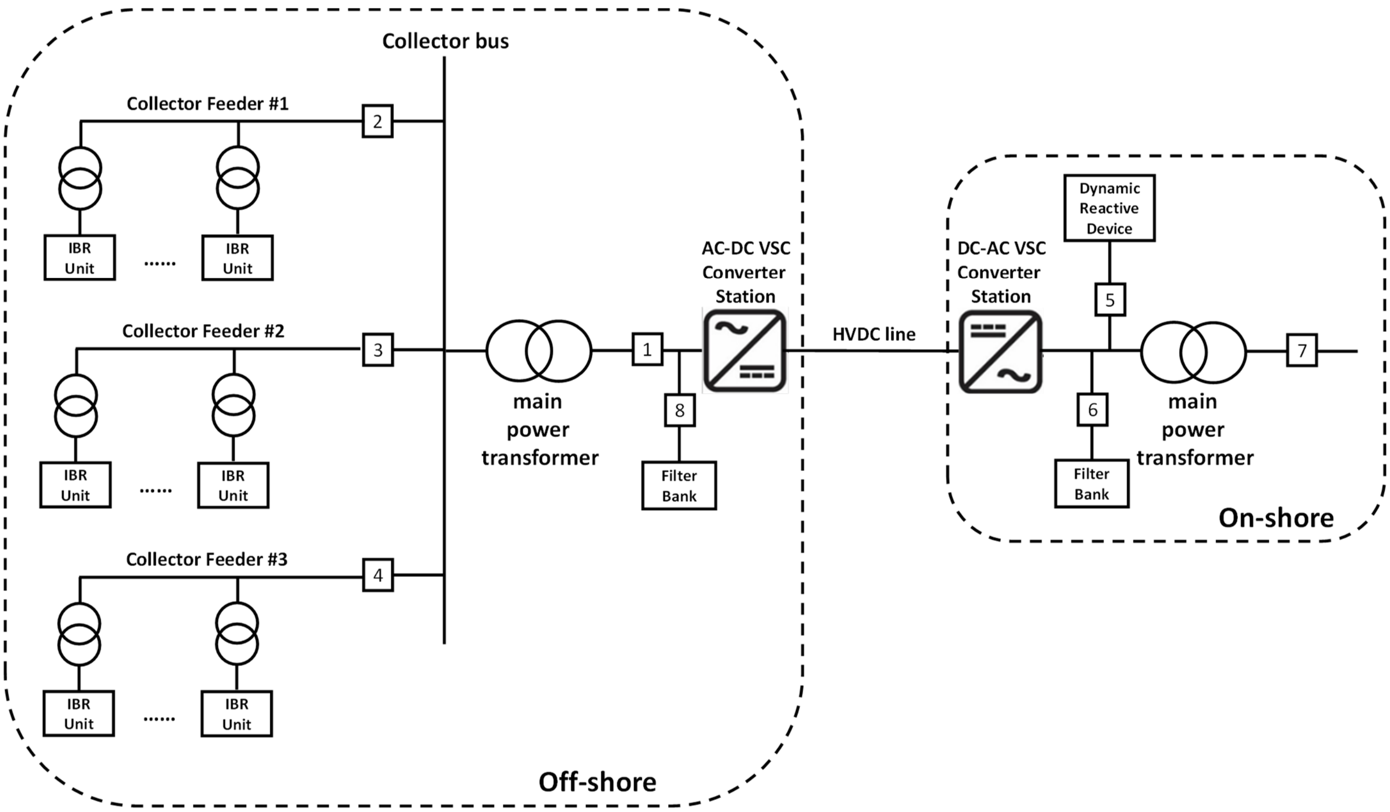

Figure 3: Typical inverter-based resource connected via dedicated VSC HVDC

SER Data: The SER data is required for circuits breaker 1, 2, 3, 4, 5, 6, 7 and 8. Circuit breakers 1 and 7 are associated with main power transformers. Circuit breakers 2, 3, and 4 are associated with the collector bus. Circuit breakers 6 and 8 are associated with filter banks and circuit breaker 5 is associated with shunt dynamic reactive device.

FR Data: The FR data is required from high side terminals of both main power transformers.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example ~~3~~4: Applicability of PRC-002 versus PRC-028

Figure ~~3~~ 4 shows an example of inverter-based resource~~IBR~~ interconnection to the transmission system via Line 34. The BES bus in substation Wu is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for the identified BES bus are per the requirements in the Reliability Standard PRC-002. ~~The IBR generating facility in this example meets the criteria set by inclusion I2 of the BES definition. Hence, ~~T~~t~~he Reliability Standard PRC-028 is applicable to the inverter-based resource~~IBR generating facility~~.

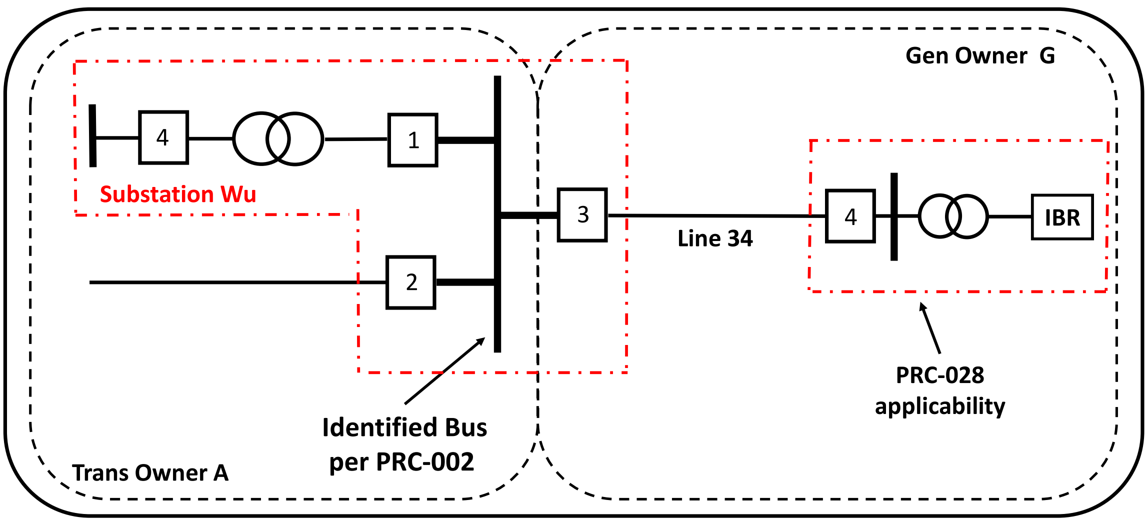

Figure ~~3~~4: Inverter-based resource~~IBR~~ Interconnection – Applicability of PRC-002 versus PRC-028

Example ~~4~~5: Transmission Owner owned Equipment within the ~~I~~inverter-~~B~~based ~~R~~resource~~IBR generating facility~~

Figure ~~4~~5 shows an example of an inverter-based resource~~IBR~~ interconnection where Transmission Owner A owns circuit breaker 3 associated with an inverter-based resource~~IBR generating facility~~. In this case, Transmission Owner A is responsible for SER data for circuit breaker 3. It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an inverter-based resource~~IBR generating facility~~. However, in cases where this is true, Transmission Owner is responsible for SER, FR, and DDR data, as applicable, required by the Reliability Standard PRC-028.

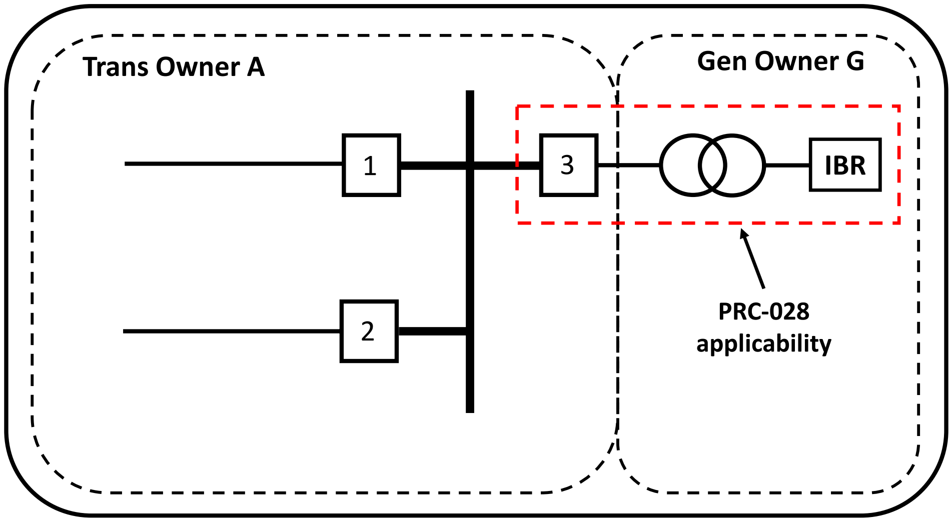

Figure ~~4~~5: Transmission Owner owned Equipment within an inverter-based resource~~IBR Plant~~

Rationale for Requirement R1

The standard requires to capture SER data from circuit breakers ~~and IBR Units~~ within the inverter-based resource~~IBR generating facility~~ associated with:~~. At least one IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus must have the data specified in R1, Part 1.2 and Part 1.3.~~

- Main power transformer(s)
- Collector bus(es), including collector feeder breakers
- Shunt static or dynamic reactive device(s), including any filter banks
- AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to inverter-based resources.

Change of state of circuit breaker position~~ and IBR Unit data~~, time stamped according to Requirement R7 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of ~~IBR's~~ inverter-based resource's ~~generating facility's~~ response during a power System disturbance. Analyses of system disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations helps determine the interruption of flows during the disturbances. ~~Recording of at least one IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus helps analysis of IBR Unit performance during BES disturbances that do not operate the interconnecting circuit breaker. One IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus is specified because it may be the most challenging location for IBR Unit to continue to ride-through during BES disturbance. For IBR Unit in commercial operation prior to the effective date of this standard, SER is data is required, if IBR Unit is capable of recording.~~

Rationale for Requirement R2

The intent is to capture sufficient FR data for Elements at each inverter-based resource~~IBR generating facility~~ to analyze the overall response of the inverter-based resource~~IBR generating facility~~ to a system disturbance. Analyses of disturbances involving widespread reduction of power output from inverter-based resource~~IBR~~s in recent years has shown that expansion of monitoring at inverter-based resource~~IBR~~ sites is necessary. The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured).

The plant level FR measurements, i.e., measured on high-side terminals of the main power transformer, specified in Requirement R2, Part 2.1 provide data at the inverter-based resource~~IBR~~ ~~generating facility~~ interconnection to the bulk power system. To cover all possible fault types, phase-to-neutral voltage recording for each phase is required to be determinable. Each phase current and residual current are required to distinguish between phase faults and ground faults. This data also facilitates determination of the fault location and cause of relay operation. The measurements of active and reactive power provide data on the overall generating facility's response to the system disturbance.

~~Analyses of system disturbances involving widespread reduction of real power output from IBRs in recent years have shown that all individual IBR Units within the IBR generating facility do not react to the disturbance identically because of their wide geographic distribution. Requirement R2, Part 2.2, requires monitoring of at least one IBR Unit, per collector bus, connected at a distance ≥ 90% of the longest collector feeder from the collector bus, ensuring that FR data is available to analyze individual IBR Unit response. It may be challenging to record/determine specified electrical quantities from IBR Unit terminals for existing installations. As such, the standard allows for recording/determining specified electrical quantities on high-side of IBR Unit transformer.~~

In some cases, the dynamic reactive device is used within the inverter-based resource~~IBR~~ ~~generating facility~~ and often connected to medium voltage collector bus. Regardless of where dynamic reactive device is connected, the output of it during system disturbances is important to understand overall performance of the plant during a disturbance. The measured or determined electrical quantities for dynamic reactive device are same as those specified to be measured/determined from high-side of main power transformer.

Recording of Electrical Quantities

For effective fault analysis, it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation. FR also shows generator output response to a system disturbance.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120 degrees, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current Ir, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Voltage Recordings
Voltages are to be recorded or accurately determined at applicable Elements as outlined in Requirement R2.

Rationale for Requirement R3
Time stamped pre- and post-trigger FR data aid in the analysis of power system operations and determination if operations were as intended.

The "Odessa Disturbance" report from September 2021 recommended high resolution oscillography data at the point of interconnection~~ and on individual IBR Units~~. The minimum recording rate of 64 samples per cycle is specified recognizing state-of-the-art for DME including storage any storage capability limitations and provides sufficient data to recreate accurate response of the inverter-based resource~~IBR~~ ~~generating facility~~ to system disturbances. ~~This higher sampling rate is particularly important for capturing transient events at the individual IBR Units.~~

Pre- and post-trigger fault data along with the SER data, all time stamped to a common clock, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Additionally, inverter-based resource~~IBR~~s ~~Units~~ employ fast acting control systems (with built in protection functions) dictating ~~IBR~~inverter-based resource's ~~generating facility's~~ response to system disturbance. ~~The FR data from IBR Units time stamped to a common clock is necessary to analyze IBR Unit and generating facilities response to system disturbances.~~ Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles. To capture the full response of inverter-based resource~~IBR generating facility~~ spread over a large geographic area, a 2 second total minimum record length synchronized to a common clock is necessary for FR data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data but are not capable of providing fault data in a single record with 120 ~~contiguous~~ continuous cycles total.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R3, Part 3.1.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R3, sub-Part 3.1.3.2 specifies a phase overvoltage or undervoltage trigger during voltage ride-through events. ~~For IBR Unit FR data triggers, Requirement R3, Part 3.2.3.1 specifies a phase overvoltage and undervoltage. Requirement R3, sub-Part 3.2.3.2 specifies a trigger for overfrequency and underfrequency to record response during frequency ride-through events.~~

The triggers specified in Requirement R3, Part 3.3 for dynamic reactive device FR data are similar to ones specified in Requirement R3, Part 3.1 for plant level FR data measured or determined on high-side of the main power transformer.

Rationale for Requirement R4

Large scale system disturbances generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and ~~IBR~~inverter-based resource's ~~generating facility's~~ response to large scale system disturbances. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event. The state-of-the-art DDR equipment is capable of continuous recording.

DDR data contains the dynamic response of the inverter-based resource~~IBR~~ ~~generating facility~~ to a system disturbance and is used for analyzing complex power system events. This recording is typically used to capture short-term and long-term disturbances. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

DDR is used to measure transient response to system disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage and current from the same phase or positive sequence for each applicable main power transformer for analysis. It is also sufficient to provide a single frequency for any of the provided voltages since all main power transformers within a inverter-based resource~~IBR~~ ~~generating facility~~ are at the same frequency. Recording of all three phases of voltage/current is not required, although this may be used to compute and record the positive sequence value(s). The electrical quantities for Real Power and Reactive Power on a three-phase basis can be measured/recorded or determined (calculated, derived, etc.).

The data requirements for PRC-028-1 are based on a system configuration assuming all normally closed circuit breakers on a BES bus are closed.

A crucial part of disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary to have DDR on high-side of the main power transformer(s) measuring the specified electrical quantities to adequately capture ~~IBR~~inverter-based resource's ~~generating facility's~~ response.

The Requirement R4, Part 4.1 requires either one phase-to-neutral or positive sequence voltage. However, the phase-to-phase voltage recording is acceptable. Since the BES operates under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Rationale for Requirement R5

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltages and frequency. The input sampling rate specified is same as one specified in the Reliability Standard PRC-002.

An output recording rate of electrical quantities of at least 60 times per second refers to the recording rate of the device. Recorded measurements of at least 60 times per second provide adequate recording speed to monitor the ~~IBR~~inverter-based resource's ~~generating facility's~~ response during power system disturbances. Since control system associated with ~~IBR~~inverter-based resources is fast acting, higher frequency recording is necessary to accurately reconstruct events. An output recording rate of 60 times per second provides this higher frequency recording while not greatly increasing data storage requirements.

Rationale for Requirement R6

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 1 millisecond accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 1 millisecond accuracy will suffice with respect to providing time synchronized data. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. Note that the recently published IEEE Std 2800 requires the DME recording plant level data be synchronized to the clock with accuracy of ± 1 microsecond accuracy; however, the accuracy requirement is set to ± 1 millisecond to strike a balance between need of accuracy and practical limitations of equipment necessary to achieve the stated accuracy.

The ~~IBR~~inverter-based resources, which are not affected by inertial time constants, make changes in power production very rapidly. To understand and analyze control decisions during system disturbances and the reasons behind them over dozens of plants ~~with possibly 100's of IBR Units~~ requires a high level of accurate time synchronization. Following provide some examples of ~~IBR~~inverter-based resource's fast response:

- Typical 90% response to a three-phase fault is <40 ms.
- Central power plant controllers issue updated commands in as little as 40 ms upon detection of change in system conditions.
- Standard closed loop voltage control response can be <200 ms.
- Instantaneous Inverter protective trip decisions such as AC or DC overvoltage or reverse DC current can be made in less than 10 ms.

Rationale for Requirement R7

Requirement R7, Part 7.1 specifies a minimum time period of 20 calendar days inclusive of the day the data was recorded for which the data to be retrievable. Data hold requests are usually initiated the same or next day following a major event, however, it takes a longer time to determine which data from which generating facility needs to be retrieved for event analysis. A 20 calendar day time period provides enough time for communication between various Entities regarding the event and need for data retrieval from DME at various generating facilities. The requestor of data has to be aware of 20 calendar day retrievability limit to ensure timely data hold requests. Requiring data retention for a longer period of time is expensive and unnecessary.

With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 20 days. To clarify the 20 calendar day time frame, let's assume that event occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 20 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 21, that is outside the 20 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER, FR and DDR data for generating facilities as per the applicability. To facilitate the analysis of system disturbances, it is important that the data is provided to the requestor within a reasonable time. Providing the data within ~~30~~15 calendar days (or the granted extension time), subject to Requirement R7, Part 7.2, allows for reasonable time to collect the data and perform any necessary computations or formatting. An entity may request an extension of the ~~30~~15 calendar days submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Disturbance analysis includes reviewing data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis. The formatting and naming convention requirements for SER, FR, and DDR are consistent with same requirements in the Reliability Standard PRC-002.

SER data: Requirement R7, Part 7.3 specifies a simple ASCII Comma Separated Value (CSV) format according to Attachment 1. It is necessary to establish a standard format as it allows data submitted by one entity or facility to be incorporated with same data provided by other entities or facilities to develop a detailed sequence of events timeline of a power system disturbance.

FR ~~and DDR~~ data: Requirement R7, Part 7.4 specifies ~~either CSV format or~~ the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the FR ~~and DDR~~ data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources. ~~The 2013 revision of the IEEE C37.111 includes an annex describing the application of the COMTRADE standard to synchrophasor data.~~

DDR data: Requirement R7, Part 7.5 specifies either CSV format with appropriate headers or the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the DDR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources. The

2013 revision of the IEEE C37.111 includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R7, Part 7.6~~5~~ specifies the IEEE C37.232 Standard for Common Format for Naming Time Sequence Data Files (COMNAME) format for naming the SER, FR and DDR data files. The lack of a common naming practice seriously hinders the event analysis and investigation process.

Rationale for Requirement R8

The standard requires that Entity restore the recording capability for SER, FR, or DDR data within 90 calendar days of the discovery of a failure. The 90 calendar day time period permitted in this requirement strikes a balance between reasonable time needed to restore capability while ensuring that recording capability is not out of service for an extended duration. If the recording capability cannot be restored within 90 calendar days due to limitations such as budget cycle, service crews, vendors, needed outages, etc., the entity is required to submit a Corrective Action Plan for restoring the recording capability to the Regional Entity and implement it. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored Element does not constitute a failure of the disturbance monitoring capability.

~~**Rationale for Requirement R9**~~

~~For Facilities in commercial operation on or before the effective date of PRC-028-1, the Implementation Plan requires applicable Entities to be fully compliant at 50% of their Facilities within three (3) calendar years of the effective date of PRC-028-1 and fully compliant at 100% of Facilities prior to January 1st, 2030. The Implementation Plan recognizes Federal Energy Regulatory Commission's directive, under Order No. 901[3], to have this standard effective and enforceable before 2030. The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan. Requirement R9, Parts 9.1 through 9.5 outlines details to be included in the Corrective Action Plan.~~

[3] See Order No. 901 at P226.

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UPDATED

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Extended, Now Open through June 17, 2024

Now Available

The formal comment period for **Project 2021-04 Modifications to PRC-002- Phase** II has been extended and is now open through **8 p.m. Eastern, Monday, June 17, 2024** for the following standards and implementation plan:

- PRC-002-5 – Disturbance Monitoring and Reporting Requirements
- PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- Implementation Plan

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

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

Additional ballots for the standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels have been extended and will now be conducted **June 5 – 17, 2024**.

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 2021-04 Modifications to PRC-002 observer list” in the Description Box.

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Open through June 14, 2024

Now Available

A 15-day formal comment period for **Project 2021-04 Modifications to PRC-002- Phase II** is open through **8 p.m. Eastern, Friday, June 14, 2024** for the following standards and implementation plan:

- PRC-002-5 – Disturbance Monitoring and Reporting Requirements
- PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
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Additional ballots for the standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 5 – 14, 2024**.

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 2021-04 Modifications to PRC-002 observer list” 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:	2021-04 Modifications to PRC-002 – Phase II | Draft 3
Comment Period Start Date:	5/31/2024
Comment Period End Date:	6/17/2024
Associated Ballots:	2021-04 Modifications to PRC-002 – Phase II Implementation Plan AB 3 OT 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 | Non-Binding Poll AB 3 NB 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 AB 3 ST 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll AB 3 NB 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 AB 3 ST

There were 61 sets of responses, including comments from approximately 144 different people from approximately 92 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the modification in “Applicability, Section 4.2. Facilities” in PRC-028-1 to remove “Non-BES Inverter Based Resources …”?

2. Do you agree with removing “Inverter Based Resources” and “IBR Unit” under Term(s) for Reliability Standards PRC-002-5 and PRC-028-1?

3. Do you agree with the standard drafting team removing Requirement R9 in Reliability Standard PRC-028-1 and adding it to the Implementation Plan since it is more like a process, not a Requirement?

4. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

5. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

6. 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
Portland General Electric Co.	Brooke Jockin	1,3,5,6		Portland General Electric Co.	Brooke Jockin	Portland General Electric	1	WECC
					Dan Mason	Portland General Electric	6	WECC
					Ryan Olson	Portland General Electric	5	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,SPP RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Matt Goldberg	ISO New England	2	NPCC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF

					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
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
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
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
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

					Tyler Brun	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
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
DTE Energy	Patricia Ireland	4		DTE Energy	Patricia Ireland	DTE Energy - Detroit Edison	4	RF
					Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC

Michele Tondalo	United Illuminating Co.	1	NPCC
Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
Randy Buswell	Vermont Electric Power Company	1	NPCC
James Grant	NYISO	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	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
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	6	NPCC

						Department of Public Service		
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	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
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Heather Harris	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC

						Wei Shao	Sacramento Municipal Utility District	1	WECC
						Foung Mua	Sacramento Municipal Utility District	4	WECC
						Nicole Goi	Sacramento Municipal Utility District	5	WECC
						Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the modification in "Applicability, Section 4.2. Facilities" in PRC-028-1 to remove "Non-BES Inverter Based Resources …"?

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

Industry comments show that the exact definition of Inverter Based Resource should be used, not the uncapitalized version that is currently in the PRC-028 draft, which is not bounded by the official definition. The footnote in the proposed standard is also an expansion of the NERC approved definition.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment

TEPC agrees with EEI's comments regarding Section 4.2.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FE supports EEI Comments which state:

EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the

Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the "Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies." and "Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard." The Purpose statement is not intended to define or expand which facilities are to be applicable to a NERC Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.

We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

PRC-028 does not apply to Reclamation.

Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

AZPS supports the following comments that were submitted by EEI on behalf of its members:

EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the "Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies." and "Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard." The Purpose statement is not intended to define or expand which facilities are to be applicable to a NERC

Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.

We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

We do not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unrestrained and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Also, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
No. Non-BES IBRs should be applicable to this standard, as it aligns with the FERC order activities and the on-going NERC Registration efforts to incorporate the non-registered BPS-connected IBRs that are owned/operated by the newly proposed Category 2 GO and GOP entities. Exclusion of these BPS-connected IBRs would significantly limit the ability to ensure that all BPS-connected IBRs have adequate data for performance evaluation/analysis during BPS/BES disturbances and data for BPS-connected IBR model validation.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
USV agrees with comments proposed by NPCC. The purpose of the project is to create a clear understanding of Non-BES and BES inverter-based resources and address gaps that exist in the current standards. With the proposed language, we foresee a lot of interpretation when it comes to inverter-based resources and note inconsistency between the three PRC standards. Suggest coordination between the three PRC standards that are currently open and progressively work towards the same or similar goal.	
Likes 0	
Dislikes 0	

Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
It is imperative that the standard drafting teams for this project as well as the 2020-02 (PRC-024 and PRC-029) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. Furthermore, this modification no longer addresses the purpose or goal of the IRPTF SAR as approved by the Standards Committee: “This SAR proposes to revise PRC-002-2 or create a new standard to address gaps within the existing standard. The goal is to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, **including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements**. Nor do these modifications address the recommendations of the IRPTF in the IRPTF Review of NERC Reliability Standards White Paper where “The IRPTF recommends **that a SAR(s) be developed** to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, **due to the continued growth of BPS-connected inverter-based resources**”.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	

It is imperative that the standard drafting teams for this project as well as the 2020-02 (PRC-024 and PRC-029) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. Furthermore, this modification no longer addresses the purpose or goal of the IRPTF SAR as approved by the Standards Committee: “This SAR proposes to revise PRC-002-2 or create a new standard to address gaps within the existing standard. The goal is to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, **including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements**. Nor do these modifications address the recommendations of the IRPTF in the IRPTF Review of NERC Reliability Standards White Paper where “The IRPTF recommends **that a SAR(s) be developed** to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, **due to the continued growth of BPS-connected inverter-based resources**”.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Industry comments show that the exact definition of Inverter Based Resource should be used, not the uncapitalized version that is currently in the PRC-028 draft, which is not bounded by the official definition. The footnote in the proposed standard is also an expansion of the NERC approved definition.	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM is in support and agreement of EEI comments.	
Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

NextEra Supports EEI Comments

EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the “Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies.” and “Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.” The Purpose statement is not intended to define or expand which facilities are to be applicable to a NERC Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.

We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No

Document Name	

Comment
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	

Comment
See EEI Comments

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	

Comment
The ISO/RTO Council (IRC) Standards Review Committee (SRC) is concerned with the removal of non-BES inverter-based resources (IBRs) from Applicability, Section 4.2, particularly if non-BES IBRs will need to be added later. Although NERC has authority over the BPS, to the extent proposed PRC-028, Section 4.2 explicitly applies to BES IBRs only, then PRC-028 would not apply to BPS resources (i.e. registered non-BES IBRs). Several other NERC standards are relying on PRC-028 for monitoring. If PRC-028 doesn't require IBR monitoring as a foundational element, then the other IBR performance standards relying on PRC-028 will likely be less effective too. Therefore, the Applicability of PRC-028 should be expanded to apply to both BES IBRs and non-BES IBRs. Ultimately, adequate data must be available from IBRs to evaluate IBR ride-through performance during BES Disturbances and to provide data for IBR model validation.

Likes 0	
Dislikes 0	

Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NextEra supports EEI's comments:

EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the "Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies." and "Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard." The Purpose statement is not intended to define or expand which facilities are to be applicable to a NERC Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.

We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.

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 RSC	
Answer	No
Document Name	
Comment	

It is imperative that the standard drafting teams for this project as well as the 2020-02 (PRC-024 and PRC-029) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards.

Furthermore, this modification no longer addresses the purpose or goal of the IRPTF SAR as approved by the Standards Committee: "This SAR proposes to revise PRC-002-2 or create a new standard to address gaps within the existing standard. The goal is to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, **including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements**. Nor do these modifications address the recommendations of the IRPTF in the IRPTF Review of NERC

Reliability Standards White Paper where “The IRPTF recommends **that a SAR(s) be developed** to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, **due to the continued growth of BPS-connected inverter-based resources**”.	
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: 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	
Until NERC and industry sort out what will be included in NON-BES IBRs, we cannot have it written in a standard.	
Likes 0	
Dislikes 0	
Response	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	

This change adds clarity to the applicability of the standard	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

AEPC signed on to ACES comments:

ACES is very appreciative of the effort put forth by the SDT to listen to industry comments and revise PRC-028-1 accordingly. It is the opinion of ACES that removing "Non-BES Inverter Based Resources" is the correct approach for this draft; however, we do not completely agree with language chosen by the SDT for Section 4.2. We recommend the following language:

4.2.1 For the purposes of this standard, "inverter-based resources" refers to a collection of 1 (one) or more of any of the following facility types that operate as a single plant/resource:

4.2 Facilities: Elements associated with inverter-based resources meeting the criteria of Inclusion I4 of the BES definition.

4.2.1.1 Individual solar photovoltaic (PV)

4.2.1.2 Type 3 and Type 4 wind turbines

4.2.1.2 In the case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource includes the VSC HVDC line.

4.2.1.3 Battery energy storage system (BESS), or

4.2.1.4 Fuel cells

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	Yes
Document Name	

Comment

AES CE supports MRO NSRF's comment on this question.

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	Yes
Document Name	

Comment

LES supports MRO NSRF's comment on this question.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	

Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF requests additional information on the future process to be used to revisit PRC-028-1 once the Rule of Procedure IBR Registration changes are approved and the NERC Glossary of Terms are updated for new IBR definitions.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	

Comment	
SMUD agrees with the SDT's decision to remove "Non-BES Inverter Based Resources" from the applicable facilities in this new version of PRC-028-1; however, we are concerned that this may be a short-term fix since FERC Order 901 directs NERC to "submit, by November 4, 2024, new or modified Reliability Standards that require disturbance monitoring data sharing and post-event performance validation for **registered IBRs** [emphasis added]." The term "registered IBRs" in FERC Order 901 includes BES IBRs registered with NERC and IBRs which will be registered according to FERC's IBR Registration Order. Once FERC approves the registration criteria proposed in NERC's rules of procedure changes submitted to FERC on March 19, 2024, the SDT will be required to modify PRC-028-1 again to include the non-BES IBRs that will be registered. This future change that would be required to PRC-028-1 is inefficient.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees with the removal of Non-BES inverter based resources, as long as this is the desired final state of the applicable facilities for this standard. However, NV Energy does not agree with moving the goal posts to obtain a desirable short-term outcome, if the intention is to revert back to the inclusion of Non-BES Inverter Based Resources at a later date.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the "Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies." and "Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard." The Purpose statement is not intended to define or expand which facilities are to be applicable to a NERC	

Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.

We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.

Likes 1	Mazza Chantal On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5;
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

ACES is very appreciative of the effort put forth by the SDT to listen to industry comments and revise PRC-028-1 accordingly. It is the opinion of ACES that removing “Non-BES Inverter Based Resources” is the correct approach for this draft; however, we do not completely agree with language chosen by the SDT for Section 4.2. We recommend the following language:

4.2 Facilities: Elements associated with inverter-based resources meeting the criteria of Inclusion I4 of the BES definition.

4.2.1 For the purposes of this standard, “inverter-based resources” refers to a collection of 1 (one) or more of any of the following facility types that operate as a single plant/resource:

4.2.1.1 Individual solar photovoltaic (PV)

4.2.1.2 Type 3 and Type 4 wind turbines

4.2.1.2 In the case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource includes the VSC HVDC line.

4.2.1.3 Battery energy storage system (BESS), or

4.2.1.4 Fuel cells

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 5,6

Answer	Yes
Document Name	
Comment	

Invenergy agrees with the drafting team’s simplification of the Applicability section.

Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	
Comment	

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the removal of Non-BES Inverter Based Resources. SIGE is concerned that the intention behind removing Non-BES Inverter Based Resources is only a short-term allowance until the Rules of Procedure changes are approved.

While SIGE recognizes the challenges the Drafting Teams are facing; the parallel development of IBR-focused Standards and IBR definitions/rules of procedure may result in ‘temporary’ Standards that may not be fully aligned across their Applicability and Facilities sections. Meaning, it seems the current open drafts are being written as stop gaps until the IBR definitions and Rules of Procedure are approved rather than pausing to focus on the definitions and Rules of Procedure first then revise the Standards.

Likes 0	
Dislikes 0	
Response	

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
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	
Mark Flanary - Midwest Reliability Organization - 10	
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 Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - 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	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Neville - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE is concerned removing “Non-BES Inverter Based Resources” from the Applicability Section 4.2 will eliminate all solar facilities with less than 75 MW of aggregated generation capacity from complying with this standard. In addition, storage facilities with less than 75 MW aggregated generation capacity would be excluded from this standard. This data is needed to have adequate data available from inverter-based resources to evaluate ride-through performance during BES Disturbances. Texas RE recommends the following verbiage (in bold):

4.2. Facilities

4.2.1 BES inverter-based resources

4.2.2 Non-BES inverter-based resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

This change would also facilitate the new GADS reporting for Solar facilities, which requires generating plants with a Plant Total Installed Capacity of 20 MW or greater per plant to submit the data.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

2. Do you agree with removing “Inverter Based Resources” and “IBR Unit” under Term(s) for Reliability Standards PRC-002-5 and PRC-028-1?	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
These definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC “directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS.”	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
The SRC disagrees with the removal of these terms from the standards. One of the benefits of developing formal definitions for IBR and IBR Unit in Project 2020-06 is that these terms, once finalized, will provide a consistent understanding of what constitutes an IBR and an IBR Unit for purposes of NERC Reliability Standards. However, developing IBR-focused standards that explicitly decline to use these standardized definitions undermines the benefits of developing Glossary-level definitions, and presents a risk that different standards will use different definitions of what constitutes an IBR, resulting in an inconsistent, difficult-to-comply-with patchwork of regulations rather than a consistent suite of IBR-related Reliability Standards. The draft 2 postings effectively explained the overlap with the work being done in Project 2020-06 so that entities could evaluate PRC-002 and PRC-028 in light of those definitions. The SRC recommends that the drafting team revise PRC-002 and PRC-028 to once again rely on the Project 2020-06 definitions of IBR and IBR Unit to help ensure consistency across IBR-related standards on the front end and avoid the need to make subsequent revisions to these standards once Project 2020-06 is complete. The SRC believes that a decision not to use the Project 2020-06 definitions should be supported by a compelling justification.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	

Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
The voters in Project 2020-06, Inverter-based Resource Glossary Terms draft #2, approved the definition of IBR on April 8, 2024, which is different than the definition proposed in Footnote 1 of PRC-028-1. Using the term “inverter-based resources” and defining it with Footnote 1 is inefficient and would create two definitions for the same resource. The SDT of PRC-028-1 should coordinate with the SDT of Project 2020-06 and NERC staff to ensure the definition of IBR and new PRC-028-1 are submitted to FERC simultaneously thereby eliminating another ballot for PRC-028-1 to add the NERC Glossary Term for IBR into the standard.	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	
These definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC “directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS.”	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
These definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC "directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS."	
Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
USV agrees with comments proposed by NPCC.	
Likes 0	
Dislikes 0	
Response	

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
No. Removing these two Terms is not aligned with the other on-going IBR standard related work throughout NERC. By removing these two Terms, it appears to have forced the creation of a new definition of "inverter-based resources" under Footnote 1 of this draft of PRC-028-1. It seems counter productive to have a unique definition of IBRs and IBR units under each different NERC standard. Having all standards aligned to the same core definitions/terms for IBRs will make all this standard development work, execution of the standards, and compliance activities more efficient for all entities involved.	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro appreciates the drafting team's efforts and opportunity to comment, and offers the following.

BC Hydro prefers that PRC-028-1 rely on an IBR definition, we understand the rationale for moving ahead while the definitions being drafted by the Project 2020-06 drafting team are being finalized.

BC Hydro requests that the drafting team clarify that the Footnote 1 is not intended to expand on the applicability scope of PRC-028-1, which does not include reactive power devices providing reactive support, such as STATCOMs as an example.

BC Hydro suggests that the Footnote 1 be (a) referenced within the Section 4.2 Facilities of PRC-028-1, and (b) revised to include a provision that IBRs are devices capable of exporting Real Power as follows.

Suggested revision to Footnote 1 – For the purpose of this standard, “inverter-based resources” refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource and can export Real Power from a primary energy source or energy storage system via a power electronics interface (such as an inverter or converter), and that is/are operated as a single resource connected to the electric power system at a common point of connection.

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy's response should be Yes. Noting the term IBR was defined under Project 2020-06, received favorable ballot by the industy but is pending final approval by the NERC BoT and FERC, FE does support removing these under Term(s)

Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No

Document Name	
Comment	

Inverter-based resource is included in the “**Purpose”** of PRC-028-1 and should be included in the Term(s) section.

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	

NextEra supports EEI's comments:

EEI supports removing Inverter Based Resources and IBR Unit under the Terms section of PRC-002-5 and PRC-028-1, noting that the term IBR was defined under Project 2020-06, received a favorable ballot by the industry and is now pending final approval by the NERC BOT and FERC.

Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with removing Inverter Based Resources (IBR) and IBR Unit as IBR Unit is unapproved and IBR refers to IBR Unit.

Please add a Standard-specific definitions section like PRC-005-6 that addresses the inverter-based resources definition in Footnote 1.

Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	

Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the removal of the as of yet unapproved terms “Inverter Based Resources” and “IBR Unit”.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	

Comment	
NextEra Supports EEI's comments: EEI supports removing Inverter Based Resources and IBR Unit under the Terms section of PRC-002-5 and PRC-028-1, noting that the term IBR was defined under Project 2020-06, received a favorable ballot by the industry and is now pending final approval by the NERC BOT and FERC.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports removing Inverter Based Resources and IBR Unit under the Terms section of PRC-002-5 and PRC-028-1, noting that the term IBR was defined under Project 2020-06, received a favorable ballot by the industry and is now pending final approval by the NERC BOT and FERC.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees with the practice of not using unapproved defined terms in Reliability Standards.	
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	
Southern Company would like more information on the plan to reintroduce the inverter data.	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM is in support and agreement of EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Support removal of the above terms from the standards PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	

Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
LES supports MRO NSRF’s comment on this question.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	

Response	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
The definition needs to be in the glossary of terms	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: 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	
Until industry and NERC DTs pass definitions, they should not be used in other standards with a capital letter. If DT needs to use lower case inverter based resource they must stipulate which ones they mean, which this draft has a footnote doing.	
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	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Reclamation agrees that these identifiers should be in the NERC Glossary of Terms and not in the standards themselves.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with the removal of unapproved defined terms in the standard. However, if the intention is that the definitions will be added at a later date when they are approved then the SDT should not include the footnote and wait until the definitions are approved through ballot. It seems like we are putting the "cart before the horse" by not having the IBR definitions approved first and working on the related standards just to meet a deadline. It will make it a duplicate process to have to come back to PRC-028 and comment/ballot again when the definitions are added.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Support removal of the above terms from the standards PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
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

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

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
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	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power 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	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE continues to support Project 2020-06 to define Inverter-based Resource and Inverter-based Resource Unit in the NERC Glossary. Texas RE encourages the various IBR drafting teams to maintain consistent footnote description(s) of inverter-based resources in various proposed standards or standard revisions pertaining to IBRs.	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the standard drafting team removing Requirement R9 in Reliability Standard PRC-028-1 and adding it to the Implementation Plan since it is more like a process, not a Requirement?

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State agrees with MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
PRC-028 does not apply to Reclamation	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy does not agree with the Implementation Plan section information titled “Process for Seeking an Extension from Compliance Dates”. Instead, we suggest the Standard follow existing Corrective Action Program (CAP) program guidance already in practice with other NERC Standards.	
Likes 0	

Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO NSRF's comment on this question.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees to removing R9. However, Southern Company **does not agree** to requiring RE approval of an extension plan. Some criteria should be provided in the implementation plan which will permit extension in cases where the procurement and/or installation of designated additional DME is beyond the control of the entity required to install the DME.	
Likes 0	
Dislikes 0	

Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD agrees with the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy agrees with removing R9 and with the concept of placing the "Process for Seeking an Extension from Compliance Dates" in the implementation Plan. However, there should be no requirement for the GO or TO to seek approval from the Regional Entity. NV Energy recommends that the SDT create clear and auditable criteria that if met, allows for the extension of compliance dates. GOs and TOs would submit notification to the Regional Entity that they will require an extension to the compliance dates, based on the met criteria. The Regional Entities' role would be to ensure that the proper criteria are indicated by the GO or TO to allow for an extension of compliance dates, rather make subjective decisions on approval of requests. This would also eliminate concerns about differences between regions in allowing for extensions.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	

Support removal of R9 from PRC-028-1 and move to the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with this change to R9.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
We do not support sub-Requirement 9.5 about submitting a Corrective Action Plan to the Regional Entity upon requesting a time extension for compliance. Request that the Drafting Team (DT) consider defining the criteria/process for the Regional Entity to follow for evaluating compliance time extensions.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: 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	

Yes, this felt more like an implementation plan than a Requirement. PGAE agrees with the DT making this change

Likes 0	
Dislikes 0	
Response	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
This approach is inconsistently applied across the standards but we are indifferent as to the appropriate location for corrective action plans.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	Yes
Document Name	

Comment

AES CE agrees that moving this language to the Implementation Plan makes sense but is concerned that the “circumstances beyond its control” language is vague and open to interpretation. Additional criteria or qualifications to evaluate individual circumstances should be included.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	Yes
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports moving the proposed PRC-028-1 Requirement R9 to the implementation plan. The NAGF does not support sub-Requirement 9.5 with regard to submitting a Corrective Action Plan to the Regional Entity upon requesting a time extension for compliance. Request that the Drafting Team (DT) consider defining the criteria/process for the Regional Entity to follow for evaluating compliance time extensions.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Scott Thompson - PNM Resources - 1,3 - WECC

Answer	Yes
Document Name	
Comment	
PNM is in support and agreement of EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	
EEI agrees that Requirement R9 is better placed in the Implementation Plan than in the Requirements of PRC-028-1.	
Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	Yes
Document Name	
Comment	
NextEra supports EEI's Comments: EEI agrees that Requirement R9 is better placed in the Implementation Plan than in the Requirements of PRC-028-1.	
Likes 0	
Dislikes 0	
Response	

Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the removal of R9 from the standard and its placement in the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes

Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the removal of Requirement R9 from PRC-028-1 and adding it to the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
NextEra supports EEI's comments: EEI agrees that Requirement R9 is better placed in the Implementation Plan than in the Requirements of PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Flanary - Midwest Reliability Organization - 10

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 Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
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	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

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

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 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	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5,6

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	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Jennifer Neville - Western Area Power Administration - 1,6

Answer	
Document Name	

Comment
Abstain.

Likes 0	
Dislikes 0	

Response

4. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024

Answer	No
Document Name	

Comment

All IBRs that enter commercial operation after the effective date of the standard should be required to comply with the PRC-028 no later than 15 months after the effective date of the standard. IBRs that have a commercial operations date more than 15 months after the effective date of the standard should be required to be compliant on their first day of commercial operation. Such facilities should be constructed to meet the requirements of the standard, and should not be eligible to operate without being compliant for 15 months after they are in commercial operation. This should be clarified in the Implementation Plan as detailed below:

Compliance Date for PRC-028-1 Requirements R1-R7 (page 3)

"For inverter-based resources facilities entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or by the commercial operation date, whichever is earlier later."

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC

Answer	No
Document Name	

Comment

It's unclear what happens if the extension is denied?	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO agrees with the majority of the implementation plan but still has concerns with the "15 calendar months following the effective date of the standard" requirement for inverter-based resources entering commercial operation after the effective date, and believes that more time is needed to properly budget, modify designs and procure equipment for projects already under development. NIPSCO proposes modifying the following language: For inverter-based resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within "36 calendar months following the effective date of the standard or by" the commercial operation date, whichever is later.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy agrees with the proposed compliance dates; however, NV Energy does not agree with the proposed "Process for Seeking an Extension from Compliance Dates" (see response to question 3.) The implementation plan requires compliance 15 calendar months after the effective date or the commercial operation date whichever is later. The WebEx discussed that facilities in commercial operation beyond the 15 months after the effective date must be compliant on the first day of commercial operation. The language should be clarified since this is an important detail.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	No
Document Name	
Comment	

It is unclear if the implementation plan compliance due date for facilities reaching COD after the effective date of PRC-028 is meant to be absolutely 15 months after the effective date of PRC-028. Given that IBRs in commercial operation on or before the effective date is previously prescribed (50% within 3 calendar years and 100% by 1/1/2030), IBRs entering CO after the effective date should just be 15 calendar months and not include "whichever is later."

Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	
Comment	

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the North American Generator Forum (NAGF) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4

Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	

Six years would be a sufficient amount of time to plan and budget for the procurement and installation of the DDR equipment barring any supply chain complications or any other delays. USV recognizes the FERC directive mandating completion by 1/1/2030, however, due to many of the IBR sites having strict language when dealing with manufacturer's warranty and having to rely on third parties, it may result in additional complications that could delay the installation and setting up of this highly specialized equipment. We recommend that the implementation period be changed to 6 years from the effective date of the standard as opposed to targeting the date of January 1, 2030.

Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF agrees with the Implementation Plan for PRC-002-5. The NAGF believes that the proposed 3-year Implementation Plan for PRC-028 is not enough time for installing new data monitoring equipment. Therefore, recommend that the DT consider a 5-year Implementation Plan for PRC-028-1.

Likes 0	
Dislikes 0	
Response	

Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	

LES supports MRO NSRF's comment on this question.

Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES CE believes that the new implementation plan language for PRC-028 around requiring compliance 15 calendar months after the effective date or the commercial operation date, whichever is later, needs to be revised. During the Webinar the SDT discussed that facilities in commercial operation beyond the 15 months after the effective date must be compliant on the first day of commercial operation. The language should be updated to clearly reflect this intention.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Under the “Compliance Date for PRC-028-1 Requirements R1-R7” section, modify the following language: For inverter-based resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within “three (3) calendar years” following the effective date of the standard or the commercial operation date, whichever is later.	
Likes 0	
Dislikes 0	

Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
The proposed 3-year Implementation Plan for PRC-028 is not enough time for installing new data monitoring equipment. Therefore, recommend that the DT consider a 5-year Implementation Plan for PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation supports an 18-month implementation time frame.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
NextEra supports EEI's comments: EEI supports the proposed Implementation Plan for both PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	

Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	

Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the simplification of the Implementation Plan for inverter-based resources entering commercial operation after the effective date of the standard.	
Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
NextEra supports EEI's comments: EEI supports the proposed Implementation Plan for both PRC-002-5 and PRC-028-1.	
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 Implementation Plan for both PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	Yes

Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: 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	

Phased implementation is reasonable and PGAE understands the 01 January 2030 100% requirement is in line with FERC 901, not the DT's timeline.

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	
Comment	

FirstEnergy supports the Implementation Plan for PRC-002-5 and PRC-028-1	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Support the implementation plans for both PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 1,6	
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

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

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

Likes 0

Dislikes 0

Response

Scott Thompson - PNM Resources - 1,3 - WECC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 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	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
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	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power 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	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends maintaining the previous verbiage of the implantation plan for the Compliance Date for PRC-028-1 Requirements R1 – R7: “Entities shall comply with Requirements R1 through R7 at 50% of **their generating plants/Facilities** within three calendar years of the effective date…” If it is changed to inverter-based resources, it is unclear how to comply with 50%. The description of inverter-based resource in Footnote 1 in PRC-028-1 appears to contradict the language of R1. The footnote description of IBR is at the collector level while Requirement R1 refers to the Point of Interconnection (POI). The implementation plan should be at the Point of Interconnection to be clear what is needed to comply with R1. Additionally, Texas RE recommends the header on page 3 say “Process for **Requesting** an Extension to Compliance Dates.” Instead of “Process for Seeking an Extension from Compliance Dates.”	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC aggrees with the majority of the implementation plan but still has two concerns that were voiced in our prior comments.	

First: the use of the term "beyond control" is ambiguous. Who gets to determine what is "beyond control?" Second: It is unclear if a Regional Entity has the authority to grant a compliance waiver. Clarification is necessary.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	
Comment	

PRC-028 will result in costs that were not previously budgeted for.   There will be a large cost to retrofit legacy equipment for monitoring and also costs for the new communications. You will also have to bring on new staff to monitor, track and maintain.

Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	
Comment	

No comment, PGAE does not comment on cost effectiveness.

Likes 0	
Dislikes 0	
Response	

Patricia Ireland - DTE Energy - 4, Group Name DTE Energy

Answer	No
Document Name	
Comment	

The cost to install FR and DDR capabilities is not value added given how the information will be utilized (rarely or never)

Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments: It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement. As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address inverter-based resources; however, we disagree with making this new standard inclusive of all BES inverter-based resources regardless of risk to the BES. In the opinion of ACES, a blanket approach requiring every BES inverter-based resource to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which inverter-based resources pose the biggest risk to the BES, and where disturbance monitoring and reporting would provide the most benefit to the BES, **before selectively** adding such capabilities. In summary, it is our recommendation that PRC-028-1 take a similar *risk-based approach as is done in PRC-002-5.*	
Likes 0	
Dislikes 0	
Response	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment	
No. The standard requires IBR owners to have a robust compliance program implemented as well as event data collection process in place. However, this version of the standard removed the requirement for any IBR Unit to have SER, FR, or DDR data in an entire IBR plant. This will not help any event analysis process as it will not allow adequate analysis of an IBR facility's abnormal performance. At a minimum, fault codes should be available from every single IBR Unit within the facility. Lack of comprehensive data has significantly affected the ERO Enterprise's ability to conduct event analysis at many facilities over the past 7 years, as reported in numerous disturbance reports. The proposed standard would lead to inadequate data available at the inverter-level to do any useful event analysis and model validation, possibly leading to ongoing inconclusive root cause analyses. This would therefore not be cost effective for the industry. In addition, new IBRs being installed today and going forward will have all the SER, FR, and DDR data capabilities included in their inverters already, which means if the standard doesn't require this data set for these inverters/resources it could result in significant underutilization of the full capabilities of this equipment to ensure they operate reliably on the BPS.	
Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES CE believes this is not a cost effective approach to meet FERC Order 901. The requirements should be based on some study criteria similar to PRC-002 to identify specific generators that impacts reliability and therefore must invest this capital in order to ensure the reliability of the BES. AES CE recommends that the SDT leverage the expertise of Project Finance SMEs at the entities to understand the feasibility of implementing this new Standard, and the potential impacts to reliability that these additional costs could incur.	
Likes 0	
Dislikes 0	
Response	

Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO NSRF's comment on this question.	
Likes 0	
Dislikes 0	

Response
Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment
The modifications to the present version of PRC-028-1 are less costly than the previous version; however, PRC-028-1 overall is not cost-effective. PRC-002 methodology for selecting BES buses that require (SER) and (FR) Data would be more appropriate and cost-effective than the present method for PRC-028. Requiring the TO and RC to identify areas that are susceptible to disturbances or have a large concentration of IBRs would benefit from DME capabilities. This would target the investment in the areas that need it most. Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response
Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment
The modifications to the present version of PRC-028-1 are less costly than the previous version; however, PRC-028-1 overall is not cost-effective. PRC-002 methodology for selecting BES buses that require (SER) and (FR) Data would be more appropriate and cost-effective than the present method for PRC-028. Requiring the TO and RC to identify areas that are susceptible to disturbances or have a large concentration of IBRs would benefit from DME capabilities. This would target the investment in the areas that need it most. Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment	
The NAGF notes that requiring data monitoring equipment at all IBR facilities is unnecessary and an excessive cost burden for existing IBR facility owners to bear which may lead to unintended adverse impacts to reliability.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Under the applicability of PRC-002, there is a process to identify the need to have FR, SER, and/or DDR capabilities. However, PRC-028 requires any GO/TO with BES inverter-based resources to have similar if not more stringent requirements for all BES inverter-based resources. For PRC-002, it is the responsibility of TOs and RCs to identify which BES elements are required to have this recording capability. Why should PRC-028, which is meant to be similar in purpose to PRC-002, be any different. We would like to understand the reliability benefit of including all BES IBR's rather than using a qualifying process like PRC-002 does with Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the North American Generator Forum (NAGF) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	

Answer	No
Document Name	

Comment

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

PRC-028-1 will result in costs that were not previously required. These costs are not simply for the design and implementation of the monitoring but also for new communications infrastructure for legacy locations or compliance related staff to monitor, track and maintain compliance where it was not required before. For those owners that stream PMU data this standard could add significant communications costs to upgrade older facilities.

These following two comments relate to possible greatly increased costs for benefits that are not necessarily effective:

A) requiring SER on breaker positions on the GSU, collector buses and feeders, shunt devices, and AC-DC/DC-AC converters seems excessive. This quantity of monitored elements could require multiple DDRs depending on location and wiring.

B) Typically, fault recording is put on either the high side or low side of the GSU, not both. Requiring both could require multiple DDRs depending on location and wiring.

We suggest that the SDT consider requiring the DME on new (future) IBR facilities rather than applying this requirement retroactively. Including this data collection at the inverter level (for some of the inverters at the IBR facility) may prove to be beneficial for analyzing reactions of IBR facilities to transmission system disturbances. Provisioning the facility to include this data collection is much easier to accomplish during the design and construction phase of the facility.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	
Comment	

PRC-028-1 will result in costs that were previously not required.

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	
Comment	

PRC-028-1 will result in costs that were not previously required. These costs are not simply for the design and implementation of the monitoring but also for new communications infrastructure for legacy locations or compliance related staff to monitor, track and maintain compliance where it was not required before. For those owners that stream PMU data this standard could add significant communications costs to upgrade older facilities. The reliability benefit of installing, maintaining, and operating monitoring capabilities on existing equipment does not justify the cost. However, NV Energy does agree that requiring monitoring capabilities on new equipment moving forward may be a cost-effective method to assist in addressing the issues set forth in the SAR and NERC Reports.

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	No
Document Name	
Comment	

It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement.

As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address inverter-based resources; however, we disagree with making this new standard inclusive of all BES inverter-based resources regardless of risk to the BES.

In the opinion of ACES, a blanket approach requiring every BES inverter-based resource to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which inverter-based resources pose the biggest risk to the BES, and where disturbance monitoring and reporting would provide the most benefit to the BES, before selectively adding such capabilities.

In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach as is done in PRC-002-5.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP has a concern that the drafting team didn't provide any viable evidence in reference to cost effectiveness. The implementation Plan mentions the various stages of implementing the requirements for PRC-028, however, there are no actual numbers to support the effort and/or determine if either standard address cost effectiveness or not. SPP recommends that the drafting team provides some type of cost analysis to support their efforts to determine if both standards address cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

FE finds not objections or concerns to the cost effectiveness of these proposals.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Reclamation agrees with the PRC-002-5 cost effectiveness but PRC-028 does not apply to Reclamation	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
It is not possible to determine cost effectiveness. Can neither agree nor disagree.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC leave the consideration of cost effectiveness to the applicable entities.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	

Answer	
Document Name	
Comment	

MRO is not able to fully evaluate the cost effectiveness of the modification. However, the recent significant modifications to PRC-002 and PRC-028 have enhanced their cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	
Comment	

Black Hills Corporation will not comment on cost effectiveness.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	

Duke Energy supports proposed EEI language for Question 5.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment	
Ameren has no comment on cost effectiveness of this project.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	
It is not possible to determine cost effectiveness. Can neither agree nor disagree.	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	
Document Name	
Comment	
N/A - PNM has not performed a cost effective study.	
Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	

Abstain from comment

Likes 0	
Dislikes 0	

Response
Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment
“See comments submitted by the Edison Electric Institute”

Likes 0	
Dislikes 0	

Response

6. Provide any additional comments for the standard drafting team to consider, if desired.

Rhonda Jones - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

Invenergy has concerns regarding R7.1. and the 20 calendar day data retention requirement for SER, FR, and DDR data. The Technical Rationale for PRC-028-1 states that, "With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable." However, PRC-028-1 will apply to many existing inverter-based resources, some of which have been operational for decades and may possess legacy equipment incapable of storing data for such an extended period of time. Invenergy proposes the below modifications to R7.1.:

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.1.1. If the recording equipment is incapable of storing 20 calendar days of data due to storage constraints, then data shall be retrievable for the maximum allowable period supported by the storage capabilities of the recording equipment, but not less than 10 calendar days.

Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) is providing the following additional comments:

Purpose Statement comments: SIGE does not support the use of Footnote 1 in the Purpose Statement. If the "inverter-based resource" definition/Footnote 1 referenced in the Purpose Statement is intended to be specific to PRC-028, then a Standard definition section should be included in PRC-028 and the "inverter-based resource" definition/Footnote 1 should be moved to the definition section (see PRC-005-6 for reference).

R1.2 comments: SIGE requests removal of "including collector feeder breakers" from R1.2 as the inclusion of collector feeder breakers has the potential to include non-BES elements.

Likes 0	
Dislikes 0	
Response	

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	
Document Name	
Comment	

The SRC submit four additional comments/requests:

1) Reinstate the language “at least one IBR unit” in the PRC-028 requirements.

2) Reinstate inverter-level requirements in PRC-028 and to all future IBR installations

3) Update the associated Technical Rationale with justification for not including past recommendations into PRC-028

4) Continuing concern from last comment period regarding DDR coverage

The SRC disagrees with the modifications made to remove the “at least one IBR Unit” language from the PRC-028 requirements.

Based on NERC’s Reliability Guideline entitled, *BPS-Connected Inverter-Based Resource Performance,* our understanding is that having IBR Unit level data is critical when investigating events. This recommendation was later reiterated in a 2nd NERC Reliability Guideline entitled, *Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*.Therefore, we see the removal of this requirement as problematic. We would like to see the “at least one IBR Unit” language added back in all applicable requirements, i.e., Parts 1.2, 1.3, 2.2. and 3.2.

The SRC requests inverter-level requirements be reinstated in PRC-028 and applied to all future IBR installations, at a minimum.

In September 2018, following unexpected performance of several large IBR plants during disturbances, NERC issued a Reliability Guideline entitled, *BPS-Connected Inverter-Based Resource Performance.*

{C}o This guideline contains a section (Chapter 6) dedicated to measurement data and performance monitoring. Within this section are “individual inverter level data” functional requirements.

{C}o The NERC guidance considers the need for inverter-level data to diagnose performance under certain types of events. For instance, the SRC understands partial tripping of plants, where only certain inverters persistently trip during events, to be a common issue.

In September 2019, NERC issued a second Reliability Guideline that again highlighted the need for inverter-level data, stating: “Data should be available from multiple sources to provide sufficient clarity as to any abnormal response or behavior within the plant. This includes plant control settings and static values, plant supervisory control and data acquisition data, sequence of events recording data, dynamic disturbance recorder data, and inverter fault codes and inverter-level dynamic recordings.”

At least one ISO/RTO has modified its Generator Interconnection Agreement (GIA) to require inverter-level data (see current version of MISO’s tariff

However, now that PRC-028 is diverging from prior NERC guidance and lowering the bar on monitoring requirements, the latest draft of PRC-028 appears to be inconsistent with NERC recommendations and reliability needs. Therefore, the SRC requests the SDT reinstate IBR Unit level requirements in PRC-028 to align with NERC Reliability Guideline recommendations.

Moreover, PRC-028 provides the foundation for monitoring performance that will be relied upon across NERC standards to validate models and identify performance issues.

To the extent PRC-028 standard does not establish an adequate foundation, other standards that rely on operational visibility are also likely to be weakened.

A mismatch between reliability needs and NERC standards will lead to fractured adoption of monitoring across the U.S. as it will require individual ISOs/RTOs and TOs to take independent action. This is already underway, given the lack of existing national standards, common in other countries.

Deferring requirements that mandate the monitoring of IBR performance may contribute to the ongoing trend of IBR performance issues.

Barriers to collecting inverter-level data for existing IBR plants should not prevent the development of inverter-level data requirements for future IBR plants needed for post-event analysis.

The PRC-028 drafting process has demonstrated challenges with retroactively applying inverter-level data requirements. Foregoing development of appropriate ‘forward-looking” standards that require inverter-level data for future IBR plants will only exacerbate this problem.

Update the Technical Rationale

The Technical Rationale should include the justification for not including inverter-level requirements as recommended by NERC Reliability Guidelines published in 2018 and 2019.

Continued concern over minimum DDR installation requirements

The SRC notes that in its previous comments, it requested clarification as to whether any or all or none of the DDRs required by PRC-028-1 Requirement R4 are required (or allowed) to be included in the minimum DDR coverage under PRC-002-5 Requirement R5 Part 5.2. The SDT’s response indicates that “PRC-002-5 does not apply to IBRs, so the DDR requirements in PRC-028 do not count toward PRC-002. No elements should be covered under both standards as this would set up a double jeopardy situation.” The SRC is concerned that as IBR penetration increases, PRC-002-5 Requirement R5 Part 5.2 may put the RC in the position of having to specify additional (and potentially unnecessary) DDR locations simply to satisfy the minimum coverage requirement, despite PRC-028-1 requiring a DDR at each main power transformer of every IBR (meaning that there will likely be enough DDR associated with IBRs to satisfy the minimum coverage requirement within the RC footprint). The SRC recommends that either the coverage requirement be eliminated, or that the coverage calculation be revised to include DDRs associated with IBRs.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment

“See comments submitted by the Edison Electric Institute”

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 5,6

Answer	
Document Name	

Comment

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

Invenergy has concerns regarding R7.1. and the 20 calendar day data retention requirement for SER, FR, and DDR data. The Technical Rationale for PRC-028-1 states that, "With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable." However, PRC-028-1 will apply to many existing inverter-based resources, some of which have been operational for decades and may possess legacy equipment incapable of storing data for such an extended period of time. Invenergy proposes the below modifications to R7.1.:

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.1.1. If the recording equipment is incapable of storing 20 calendar days of data due to storage constraints, then data shall be retrievable for the maximum allowable period supported by the storage capabilities of the recording equipment, but not less than 10 calendar days.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	

Comment

NextEra supports EEI's comments:

EEI offer the following additional Comments:

PRC-028-1 Comments:

Purpose Statement Comments: EEI does not support the addition of Footnote 1 to the Purpose Statement because it inappropriately changes the applicability of PRC-028, outside of the Applicability Section.

Applicability Section Comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.

Requirement R1 Comments:

Subpart 1.1: EEI does not support footnote 2 because it identifies facility scope that is not identified in the Applicability Section and appears to go beyond what was allowed in the approved SAR.

Subpart 1.4: EEI does not support the addition of VSC HVDC equipment because it was not included in the industry approved definition of IBR or this SAR. While EEI is not opposed to including VSC-HVDC equipment to this Reliability Standard if that equipment is in fact creating reliability concerns, no technical justification has been provided to clarify why this is necessary. To address our concern, we ask that that the SAR be revised to include this equipment and submit a technical justification document, as required by the Rules of Procedure (see Standard Processes Manual, Appendix 3a).

Requirement R7 Comments and associated VSLs:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized.

VSL for R7: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

PRC-002-5 Comments:

Applicability Section comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary.

Footnote 2: EEI finds footnote 2 to be confusing and potentially in conflict with the Applicability Section. In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states "For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1." We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources (undefined in this standard) are not included. Yet footnote 2 seems to imply BES IBRs connected to a common bus at the same voltage level within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	
Comment	

N/A

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	

It is the opinion of ACES that Section 4.2 should be comprehensive and stand-alone; therefore, we disagree with using footnotes to prescribe which inverter-based resources are applicable to this standard. We recommend creating an all-inclusive list as a sub-section of Section 4.2 as shown in our response to question 1.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	
Comment	

NextEra supports EEI's Comments:

EEI offer the following additional Comments:

PRC-028-1 Comments:

Purpose Statement Comments: EEI does not support the addition of Footnote 1 to the Purpose Statement because it inappropriately changes the applicability of PRC-028, outside of the Applicability Section.

Applicability Section Comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.

Requirement R1 Comments:

Subpart 1.1: EEI does not support footnote 2 because it identifies facility scope that is not identified in the Applicability Section and appears to go beyond what was allowed in the approved SAR.

Subpart 1.4: EEI does not support the addition of VSC HVDC equipment because it was not included in the industry approved definition of IBR or this SAR. While EEI is not opposed to including VSC-HVDC equipment to this Reliability Standard if that equipment is in fact creating reliability concerns, no technical justification has been provided to clarify why this is necessary. To address our concern, we ask that that the SAR be revised to include this equipment and submit a technical justification document, as required by the Rules of Procedure (see Standard Processes Manual, Appendix 3a).

Requirement R7 Comments and associated VSLs:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized.

VSL for R7: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

PRC-028-1

1. Section B: What is the purpose of removing the need for recording data at the inverter level? It seems like this data is important to record and monitor.

PRC-002-5

1. This document states *"Disturbance monitoring and reporting requirements for inverter-based resources are addressed in PRC-028."*, however, PRC-028-1 draft has removed the requirement for IBR monitoring/reporting.

A general comment: IEEE 2800 does a great job addressing IBRs and could be referenced when making these types of updates for IBRs.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI offer the following additional Comments:

PRC-028-1 Comments:

Purpose Statement Comments: EEI does not support the addition of Footnote 1 to the Purpose Statement because it inappropriately changes the applicability of PRC-028, outside of the Applicability Section.

Applicability Section Comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.

Requirement R1 Comments:

Subpart 1.1: EEI does not support footnote 2 because it identifies facility scope that is not identified in the Applicability Section and appears to go beyond what was allowed in the approved SAR.

Subpart 1.4: EEI does not support the addition of VSC HVDC equipment because it was not included in the industry approved definition of IBR or this SAR. While EEI is not opposed to including VSC-HVDC equipment to this Reliability Standard if that equipment is in fact creating reliability concerns, no technical justification has been provided to clarify why this is necessary. To address our concern, we ask that that the SAR be revised to include this equipment and submit a technical justification document, as required by the Rules of Procedure (see Standard Processes Manual, Appendix 3a).

Requirement R7 Comments and associated VSLs:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized.

VSL for R7: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

PRC-002-5 Comments:

Applicability Section comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary.

Footnote 2: EEI finds footnote 2 to be confusing and potentially in conflict with the Applicability Section. In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states "For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1." We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources (undefined in this standard) are not included. Yet footnote 2 seems to imply BES IBRs connected to a common bus at the same voltage level within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.

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	

The standard specific definition for inverter-based resource found in PRC-028 footnote 1 should be placed into item #6 of the **"A. Introduction"** section, as can be seen was done for PRC-005-6 rather than being defined in the footnote.

Unless the power level of a collection system feeder breaker is > 75 MVA, the collection system feeder breaker specified in Section 1.2 of the proposed PRC-028 overreaches the BES definition for inverter-based resource.

Southern Company does not agree with the language in PRC-028, R8 requiring a Corrective Action Plan to be submitted to the **Regional Entity**. If at any time a Regional Entity desires to review a TO's or GO's Corrective Action Plans, they have the authority to request them. Simply requiring the Corrective Action Plans to be submitted to the Regional Entity with no requirement for the Regional Entity to do something with them is purely administrative and does nothing to improve the reliability of the Bulk Electric System. Further, the timely development and implementation of a Corrective Action Plan needed to repair equipment can be thoroughly examined during an audit engagement. This same reasoning applies to PRC-002, R12 and is also recommended to be removed.

Some provision in PRC-028, R7 is needed for an exception to the data delivery requirements for DME equipment that is being repaired as permitted by PRC-028, R8.

Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	

Document Name	
Comment	

In addition to EEI's comments, We ask the question, how will new standard be impacted by the new upcoming IBR registration?

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	

Texas RE recommends including a timeframe for implementing the CAPs in both PRC-002-5 Requirement R12 and PRC-028-1 Requirement R8.

In PRC-002-5, Requirement 12 there seems to be an open-ended timeframe for implementing the corrective action plan. Texas RE suggests the following for R12 second bullet:

- Submit a Corrective Action Plan (CAP) and the specific implementation schedule to the Regional Entity within 90 calendar days and implement the CAP according to the timeline specified. The timeline for implementing the CAP shall be within 9 months of the discovery, unless specific reasons for not meeting the timeline is approved by the Regional Entity.

In PRC-028-1, Requirement 8 there seems to be an open-ended timeframe for implementing the corrective action plan. Texas RE suggests the following for R8 second bullet:

- Submit a Corrective Action Plan (CAP) and the specific implementation schedule to the Regional Entity within 90 calendar days and implement the CAP according to the timeline specified. The timeline for implementing the CAP shall be within 9 months of the discovery, unless specific reasons for not meeting the timeline is approved by the Regional Entity.

Synchronous Condensers are dynamic reactive power compensation devices that are becoming essential for stabilizing the grid with the rapid additions of IBRs. Disturbance data from these devices will be valuable when evaluating the BPS disturbances.

Texas RE suggests that the SDT clearly state that the SER data for circuit breakers associated with standalone synchronous condensers and synchronous condensers co-located at the IBR facility(ies) are included in the PRC-028-1 Requirement R1.

Texas RE recommends the following verbiage (in bold):

R1, 1.3 Shunt static or dynamic reactive device(s), **including any filter banks and synchronous condensers.**

Texas RE notes that the redline version does not match the clean version. Please verify that the Draft 3, "redline to last posted" document matches with the draft 3, "clean" version of PRC-028-1 document.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 6

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	

Document Name	
Comment	

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	
Comment	

The NAGF provides the following additional comments for consideration:

a. General Comments:

i. The NAGF does not agree with requiring that electronic files be provided only in a format that is established by an outside organization. While NAGF acknowledges that C37.111 is the format most used presently, there must still be an option to provide data in a format not controlled by an outside standard as dictated by NERC Rules of Procedure Section 302.6 "Completeness — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance." Therefore, the NAGF recommends that the proposed PRC-002-5 sub-Requirement 11.4 and PRC-028-1 sub-Requirement 7.4 keep the option for providing data in CSV format.

b. PRC-028-1:

i. Requirement 1.1- Please explicitly clarify for offshore wind connected VSC-HVDC plants if the main power transformer includes only the inverter (onshore) transformer or it includes the offshore (rectifier) converter transformer. Note that, for a VSC-HVDC connected offshore wind, the rectifier side reactive power device status will have little impact on the onshore grid and bulk electric system reliability.

ii. Requirement 1.2:

1) the individual feeder buses are not considered BES elements per the NERC BES Definition Reference Document Volume 2, April 2014. It is unclear if the individual feeder-collector bus breakers, which connect to the collector bus, are considered BES. The NAGF requests clarification from the DT on this matter.

2) The NAGF requests clarification for recording of the collector system CB and protection system status for the offshore wind AC system

iii. Requirement 1.3:

1) The NAGF notes that the proposed narrative has the potential to apply to low voltage auxiliary equipment that is not considered BES. Recommend revising the narrative accordingly.

2) Is the synchronous condenser within the IBR plant also considered a part of "dynamic reactive power device(s)"? Note that in most IBR plant designs the synchronous condenser may not provide reactive power compensation; its purpose is to strengthen the grid at the IBR plant POI.

iv. The NAGF requests the DT to consider revising Requirement R1.1 – R1.3 language to clarify the rectifier side data monitoring requirements for VSC-HVDC connected offshore wind facilities.

v. Page 3, footnotes 1 and 2 – recommend moving the footnotes under the Introduction Section – Definitions Used in this Standard (similar to PRC-005-6).

vi. Requirement R7 – Recommend that the narrative be modified to include an exception for missing data that is associated with Corrective Action Plan activities.

vii. Requirement R8 – The NAGF does not see the value of submitting the CorrectiveA ction Plan to the Regional Entity and recommends deleting the associated bullet. This would also apply to PRC-002-5 Requirement R12.

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

Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.

Answer	
Document Name	

Comment

PRC-028: Comments are below:

- R1 Recommend replacing circuit breakers with Interrupting Devices
- R1.2 Recommend replacing collector feeder breakers with collector Interrupting Devices
-
    - Each Transmission Owner and Generator Owner shall have sequence of event recording (SER) data for the following Elements circuit breaker position (open/close) sequence of event recording (SER) data for Interrupting Devices that it owns associated with: *[Violation*

Risk Factor: Lower] [Time Horizon: Long-term Planning] Circuit breaker position (open/close) for circuit breakers associated with the main Main power transformer(s)2.
  - cCollector bus(es), including collector Interrupting Devices, and.

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

Kinte Whitehead - Exelon - 3	
Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5	
Answer	
Document Name	

Comment

LES supports MRO NSRF's comment on this question.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

Testing and demonstrating performance could be a challenge without further guidance on expectations.

· Many existing devices used for fault recording (SEL-351 for example) cannot meet the 2.0 second duration in R3.1.1. A duration of 1.0 second would better align with equipment capabilities. Perhaps the clause could be written that all new equipment should have the 2.0 second duration capability while existing equipment has requirements in-line with the capabilities of the equipment installed over the past few years.

Likes 0	
Dislikes 0	

Response

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

This latest draft of PRC-028-1 continues to diverge further from the IEEE 2800-2022 standard, which is the de facto standard for IBR plants interconnecting with electric transmission systems. This PRC-028-1 standard and other NERC IBR-focused standards should be conforming to/matching the IEEE 2800 standard unless there is excessively strong and clear risk evidence that there is a need to go beyond the requirements in IEEE 2800. Any NERC IBR-focused standard that creates requirements that are less than those in IEEE 2800 is incorrect and faulty.

A lot of the SER/FR/DDR capabilities may not be available in existing IBR plants already connected and operating on the grid. Creating a NERC standard for both existing IBR plants and new/future IBR plants is a difficult task, but creating a standard that is the least common denominator of the capabilities of existing and new facilities would result in a watered-down standard that would not be effective, not be cost effective, and not be valuable in achieving the reliable interconnection and operation of these IBR plants going forward. New IBR plants will most likely be designed to the IEEE 2800 standard going forward, and all these SER/FR/DDR data capture and recording capabilities are therefore all available today and a new NERC standard for these IBRs should be made to utilize these data capabilities for reliable BPS operations. The SER/FR/DDR data sampling rates and data retention rates for IBR units at existing IBR plants would add cost and would require adequate timeframe to implement (as already identified in the draft Implementation Plan for PRC-028-1), but removing these requirements from new/future IBR plants to account for limitations of existing IBR resources seems to go in a negative direction and should have a technically backed justification if it is to remain in the standard as it will set back the industry by significantly underutilizing the full capabilities of new inverters being connected to the grid now and into the future.

Further highlighting the point above, the 2021 Odessa Disturbance report and the NERC IBR Reliability Guideline document both give a recommendation to include SER data for all IBR units (i.e. all inverters) and to include FR/DDR data on some IBR units on the collector busses at IBR plants. These documents point to this Project 2021-04 and recommends including these recommendations as requirements in the updated standard(s).

Related to the 2021 Odessa Disturbance report, in the updated PRC-028-1 Technical Rationale document, page 10 gives reference to the 2021 Odessa Disturbance report. However, in this lasted PRC-028-1 Technical Rational document update there is a redline removal of the report's recommendation of high-resolution oscillography data for individual IBR units. This redline removal should not have occurred as it removes a key recommendation from the 2021 Odessa report that is specifically important to Project 2021-04 and the new draft PRC-028-1 standard. This redline removal should be added back into the technical rational document and the IBR unit level SER/FR/DDR requirements should be added back into the draft PRC-028-1 standard.

In continuing the topic of IBR-related NERC Standards not adopting the IEEE 2800-2022 standard, the PRC-002 and the new PRC-028-1 standard both put into place requirements that adopt/require the use of the IEEE C37.111 COMTRADE standard and the IEEE C37.232 COMNAME standard. The language in the PRC-002 and PRC-028 Technical Rational documents highlight that requiring these IEEE industry standards helps the industry with the analysis and other work that is required from these standards. It is exactly that same reason why these updated NERC standards should adopt the IEEE 2800-2022 standard requirements; this would give the industry consistency and clarity on all technical requirements going forward for BPS-connected IBRs. This continued inconsistency regarding NERC's approach and opinion in this area of IEEE 2800 standard adoption should be addressed.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPC signed on to ACES comments:

It is the opinion of ACES that Section 4.2 should be comprehensive and stand-alone; therefore, we disagree with using footnotes to prescribe which inverter-based resources are applicable to this standard. We recommend creating an all-inclusive list as a sub-section of Section 4.2 as shown in our response to question 1.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

WEC Energy Group supports the additional comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Patricia Ireland - DTE Energy - 4, Group Name DTE Energy

Answer	
Document Name	

Comment

We have had no disturbances since the implementation of PRC-002 monitoring. Installation of additional monitoring equipment at all IBR sites will increase capital and operational costs for a very low likelihood event and is not a cost effective approach to protecting the grid. If there are specific regions with a higher risk (history) of disturbance, perhaps the PRC-028 applicability could be amended to include a geographic/regional filter

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	

Document Name	
Comment	

Regarding proposed EOP-002-5 R12 changes, the updated language does not address updates to the CAP and its timeline and could lead to a PNC if an entity is unable to meet the target dates originally provided to the Regional Entity.

Would recommend revising the language to one of the following options for the second bullet under R12:

"Submit a Corrective Action Plan (CAP) to the Regional Entity (RE) within 90 calendar days and then implement it in accordance with the most up to date CAP timeline submitted to the RE."

OR

"Submit a Corrective Action Plan (CAP) to the Regional Entity (RE) within 90 calendar days and then implement it according to CAP timeline or submit an updated CAP to the RE prior to the CAP timeline target."

Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: 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	

Requirement 2.2 “shunt dynamic reactive device data” could be replaced with FACTS. MOD-025/-026 project uses FACTS to refer to these devices and capture Synchronous Condensers, STATCOMS, SVCS, etc. This DT should do the same, so the intent of which devices are intended are the same. Uniformity across standards and standard families is critical for ensuring compliance with the requirements and equipment.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	

For R1, include “BES” in R1.2 and R1.3 language.

Consideration should be made regarding future overall cost and manufacturer recording equipment availability.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

General Comments:

(From NAGF) We do not agree with requiring that electronic files be provided only in a format that is established by an outside organization. Although C37.111 is the format most used currently, there must still be an option to provide data in a format not controlled by an outside standard as dictated by NERC Rules of Procedure Section 302.6 “Completeness — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.”

PRC-028-1:

i. (From NAGF) Requirement 1.2 - the individual collector buses are not considered BES elements per the NERC BES Definition Reference Document Volume 2, April 2014. Recommend revising the narrative accordingly.

ii. (From NAGF) Requirement 1.3 – the proposed narrative has the potential to apply to low voltage auxiliary equipment that is not considered BES. Recommend revising the narrative accordingly.

iii. (From NAGF) Requirement R7 – Recommend that the narrative be modified to include an exception for missing data that is associated with Corrective Action Plan activities.

iv. (From EEI) Should align Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

v. (From EEI) Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. Requirements should be the same.

vi. (From EEI) VSL for R7: Align the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

vii. (From NAGF) Requirement R8 – Do not see the value of submitting the Corrective

Action Plan to the Regional Entity and recommends deleting the associated bullet.

PRC-002:

(From EEI) Footnote 2: In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states “For the purposes of this standard, “directly connected” BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1.” We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources (undefined in this standard) are not included. Yet footnote 2 seems to imply BES IBRs connected to a common bus at the

same voltage level within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.

Likes 0	
Dislikes 0	

Response
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment
1. Requirement R7 as drafted seems to imply that in case a failure to record data that is discovered while responding to a data request from an applicable entity, that would constitute a violation of R7. BC Hydro recommends that R7 be revised to clarify that a recording equipment failure would not constitute a compliance violation to R7. 2. The PRC-028-1 Technical Rationale states on page 13 (Rationale for Requirement R7 section) that, unless an extension is granted, “data has to be provided to the requestor within 20 calendar days after a request”. This appears to be in conflict with R7 Part 7.2, which states that “Data subject to Part 7.1 shall be provided within 15 calendar days of a request”. Please clarify and revise accordingly. 3. The VSL Table for PRC-028-1 R7 does not seem to set a severity level in case an extension is granted per R7 Part 7.2., e.g. a delay in providing data per the extended deadline does not factor in. Specifically, if an entity were granted an extension to 30 calendar days and provided the required data any number of days past Day 30 could not be assessed a severity level.

Likes 0	
Dislikes 0	

Response
Rob Robertson - Leeward Renewable Energy - 5

Answer	
Document Name	

Comment
We appreciate some significant improvements in the draft Standard in response to previous comments, particularly removing the requirement for Sequence of Event Recording (SER) and Fault Recording (FR) at individual Inverter-Based Resource (IBR) units, and increasing the plant size threshold for PRC-028 compliance from 20 MVA to Bulk Electric System (BES) resources, which are generally 75 MVA and greater. These improvements, which are noted at the end of our comments, are important and should be retained in the final Standard.

However, concerns expressed by Leeward Renewables in the most recent comment period, Pine Gate Renewables in the initial comment period, and others have not been fully addressed. These concerns include the cost and burden of 1. Retroactively applying the standard to existing plants and 2. Applying the requirements to smaller plants.{C}[MG1]{C}

We believe the costs and benefits of the proposed standard can be better balanced by 1. Only applying the data collection requirements to plants that sign an interconnection agreement after the effective date of the standard, and 2. Only requiring data collection at IBR generating plants larger than 500 MVA. These changes would greatly reduce the compliance cost and burden while optimizing reliability benefits, as explained below. These changes are also necessary to reduce the disparity between the strict requirements on IBRs in PRC-028 relative to the requirements on synchronous generators in PRC-002, which could result in undue discrimination against IBRs.

1. The Standard's requirements should only apply prospectively, not retroactively to existing plants

Applying the PRC-028 requirements retroactively to existing generators, as the current draft proposes, greatly exacerbates the cost and burden on generators with minimal benefit. Applying PRC-028 prospectively and not retroactively would avoid the highly costly retrofit of existing facilities, costs that in most cases cannot be recovered by plant owners because existing IBR generators typically sell their output at a fixed price under a long-term power purchase agreement. As noted below, PRC-029 and PRC-030, as well as other modeling and validation Standards revisions that are underway, apply to both existing and new resources. As a result, any concerns about the reliability performance of existing resources will be addressed through those Standards, and thus need not be addressed with PRC-030.

In the initial draft, the requirement to install SER at IBR units in part 1.2 of R1 had an exemption that "IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded," but that was removed. In the current draft, all requirements apply to all existing and new IBR resources. The retroactive requirement to install SER at IBR units may be particularly challenging in cases in which the OEM that manufactured the inverter is no longer in business, as the records produced by some inverter models are proprietary and require OEM intervention to provide in readable format to the generator owner.

The cost and implementation burden for retrofits is typically much higher than if the data collection equipment were planned and installed as part of initial plant construction. For example, in many cases new data communication wires may have to be run across existing wires, suitable locations must be found to add data collection, storage, and transmission equipment and deliver power to that equipment, and other changes that would be far less costly if they were planned during initial plant design. Adding this equipment also adds ongoing operations and maintenance and compliance costs for that equipment.

Retroactive requirements also impose a much greater financial burden on the generator as those costs cannot typically be recovered once a power purchase agreement has been signed. These unexpected and unrecoverable costs are far more concerning to lenders and other generation project financiers as they were not accounted for during the project's financing. As a result, retroactive requirements set a bad precedent by introducing regulatory uncertainty that makes future generation investment more uncertain and risky, and likely more costly by forcing financiers to charge higher risk premiums.

2. The Standard should only apply to large generators[MG2]

Only applying the requirements to larger IBR plants will greatly reduce the total cost and burden of compliance. The large fixed costs associated with installing and operating the required data collection, storage, and transmission equipment make up a larger share of the total cost of smaller plants. Only applying PRC-028 to larger plants will also make it more comparable to the PRC-002 companion standard for synchronous generators, avoiding undue discrimination against IBRs. As noted below, PRC-029 and PRC-030, as well as other modeling and validation Standards revisions that are underway, would apply to small IBR resources under NERC's IBR registration proposal. As a result, any concerns about the reliability performance of smaller IBR resources will be addressed through those Standards, and thus need not be addressed with PRC-030.

To make the cost of PRC-028 more reasonable while preserving the value of the proposed data collection, as well as avoiding undue discrimination against IBRs relative to synchronous generators, we suggest that data collection in PRC-028 only be required at plants that are 500 MVA and greater. This is the plant size threshold at which synchronous generator dynamic disturbance data collection is required in the PRC-002 standard. If the TO or RC/PC can compellingly demonstrate that smaller new plants should be required to comply with PRC-028's data collection requirements due to local reliability concerns, such as weak grid issues or high penetrations of IBRs in a local area, then that should be allowed. That would avoid an unnecessary cost burden for many smaller plants.

IBR wind, solar, and storage plants are highly modular, so larger IBR plants typically contain the same equipment as smaller plants, just in a larger aggregation (*e.g.,* more collector feeders). Because larger IBR plants are typically just larger aggregations of the equipment in smaller plants, it should be possible to infer the detailed behavior of smaller plants during a disturbance based on the performance of larger plants that are nearby and use similar equipment.

Other Standards and FERC Orders address the reliability concerns addressed by PRC-028, particularly for existing or small IBRs

Regarding potential reliability benefits of the proposed standard, we agree that ride-through issues at some IBRs have presented a legitimate reliability concern. However, the ride-through concerns PRC-028 is primarily attempting to understand have already been addressed by Federal Energy Regulatory Commission (FERC) Order 2023, the draft PRC-029 and PRC-030 Standards that are currently out for comment and balloting, as well as ongoing Standards revisions to require IBR plant modeling and validation of those models. In particular, reliability concerns about smaller and existing plants are being addressed by these Standards, and thus need not be addressed through PRC-030.

The draft PRC-029 Standard requires all existing and new generators to meet the standard, though existing generators can file for an equipment limitation exemption. Obtaining an exemption requires the owner of the existing generator to document and communicate to the Planning Coordinator "**6.1.2.** Which aspects of voltage ride-through requirements that the IBR would be unable to meet" and "**6.1.3** Identify the specific piece(s) of equipment causing the limitation," so it will be known which existing plants are unable to ride through and why. PRC-030 provides an even more open-ended tool for identifying and addressing unexpected losses of IBR generation, including from both new and existing generators.

In addition, the recent adoption of FERC Order 2023 directly addresses many of the concerns PRC-28 is attempting to address, as it imposes mandatory requirements to fully ride-through grid disturbances and to accurately validate models of plant performance at the sub-second transient timescale. Prior to the adoption of Order 2023 and the development of other NERC Standards, the proposed requirements of PRC-028 may have provided a significant reliability benefit by improving understanding of the ride-through performance of IBRs, and thus helping to identify solutions to any concerns. However, now that FERC Order 2023 and the other NERC Standards have solved many of those concerns by requiring ride-through performance and accurate modeling of sub-second plant performance, it is not clear what reliability benefit PRC-028 might provide.

To the extent the value of PRC-028 was to gather information to help craft improved ride-through requirements through PRC-029, PRC-030, and FERC Order 2023, the window for that opportunity is closing this year, or in the case of FERC Order 2023, has already closed. Data collection equipment installed by the year 2030 pursuant to PRC-028 will not help with designing those standards.

Improvements since the previous draft of PRC-028

As noted above, we appreciate some significant improvements in the draft Standard in response to previous comments. These improvements are important and should be retained in the final Standard:

-Sequence of Event Recording and Fault Recording at individual IBR units is no longer required

-Increasing the plant size threshold for PRC-028 compliance from 20 MVA to BES resources, which are generally 75 MVA and greater

However, concerns about the cost and burden of retroactive application and the application to smaller plants remain, as noted above. Even with the above improvements, the cost and burden of compliance is still significant.

The drafting team even noted the burden at pages 125-126 in the Consideration of Comments document for the initial comment period by saying "The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan."

There are also significant concerns about the disparity between the strict requirements on IBRs in PRC-028 relative to the requirements on synchronous generators in PRC-002, which could result in undue discrimination against IBRs. For example, R3 in PRC-028 requires IBRs to have FR for 2 seconds (120 cycles) following a disturbance, versus a requirement in PRC-002 for synchronous generators to only record for 30 cycles following a disturbance. IBR behavior is not inherently different enough to justify this difference, and the duration of disturbances faced by IBRs and synchronous generators are identical. There are technical hurdles and cost burdens associated with longer event reports, as they can start to fill up the device working memories and can inadvertently erase older records as those fill up. This is especially challenging when retroactively applying this requirement to sites with legacy data acquisition and storage. Similar concerns are caused by the requirement in PRC-028 R5 for IBRs to have dynamic disturbance recording at a rate of 60 times per second, versus 30 times per second for non-IBRs in PRC-002. As a final example, the synchronization requirement in R6 in PRC-028 is 1 millisecond, versus 2 milliseconds in PRC-002.

Given that there are finite resources for complying with all NERC requirements, we are concerned that PRC-028 as proposed could actually undermine reliability by distracting from more pressing reliability needs. We believe the revisions we have proposed to exempt existing and smaller plants and better align the requirements with those imposed on synchronous generators in PRC-002 will result in a Standard that better balances the cost of complying with the Standard with its reliability benefit.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of its members regarding PRC-028 Requirement 7:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized.

AZPS requested that 30 days be used for both synchronous generators and IBRS.

VSL for R7: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

AZPS supports the following comments that were submitted by EEI on behalf of their members in regards to PRC-002:

Applicability Section comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary.

Footnote 2: EEI finds footnote 2 to be confusing and potentially in conflict with the Applicability Section. In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states “For the purposes of this standard, “directly connected” BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1.” We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources (undefined in this standard) are not included. Yet footnote 2 seems to imply BES IBRs connected to a common bus at the same voltage level within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment

Reclamation does not agree with the modifications to the wording of BES Elements in R6 and R7 in the “Violation Severity Levels” section. ‘Element’ is sufficiently defined in the NERC Glossary of terms and ‘BES Element’ encompasses the required equipment (elements) for Disturbance Monitoring. Reclamation recommends keeping the original wording “for all applicable BES Elements”.

Reclamation concurs that all IBR resources should have and maintain their own separate standards.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

FE supports EEI's comments which offers the following suggestions:

PRC-028-1 Comments:

Purpose Statement Comments: EEI does not support the addition of Footnote 1 to the Purpose Statement because it inappropriately changes the applicability of PRC-028, outside of the Applicability Section.

Applicability Section Comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.

Requirement R1 Comments:

Subpart 1.1: EEI does not support footnote 2 because it identifies facility scope that is not identified in the Applicability Section and appears to go beyond what was allowed in the approved SAR.

Subpart 1.4: EEI does not support the addition of VSC HVDC equipment because it was not included in the industry approved definition of IBR or this SAR. While EEI is not opposed to including VSC-HVDC equipment to this Reliability Standard if that equipment is in fact creating reliability concerns, no technical justification has been provided to clarify why this is necessary. To address our concern, we ask that that the SAR be revised to include this equipment and submit a technical justification document, as required by the Rules of Procedure (see Standard Processes Manual, Appendix 3a).

Requirement R7 Comments and associated VSLs:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized.

VSL for R7: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

PRC-002-5 Comments:
Applicability Section comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary.
Footnote 2: EEI finds footnote 2 to be confusing and potentially in conflict with the Applicability Section. In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states "For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1." We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources (undefined in this standard) are not included. Yet footnote 2 seems to imply BES IBRs connected to a common bus at the same voltage level within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

Tri-state would like to see Part 7.1 back to the 30 calendar days. 15 days is not enough time.

Likes 0	
Dislikes 0	

Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
For PRC-028-1, R2.2, should it read “Shunt dynamic reactive device FR data” instead of “Shunt dynamic reactive device data”?	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	
Document Name	
Comment	
TEPC agrees with EEI's comments regarding both PEC-002 and PRC-028: PRC-002-5 - EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary. PRC-028-1 - EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP applauds the efforts of the standards drafting team for their continued work on this project. We believe that the newest drafts of both standards are greatly improved as compared to their predecessors. AEP is concerned however by recent revisions to PRC-028 R7.2, where all data requested in R7 must be provided within 15 days, rather than the 30 days allowed in the previous draft. In some cases, it will be very difficult to obtain, quality check, and	

provide this data within a 15-day window. Indeed, extensions might even be necessary in these cases. AEP seeks clarity from the standards drafting team regarding the justification for this, as the current draft of the Technical Rationale document provides no insight. During the webinar on 6/4/2024, the question was asked if a synchronous condenser is to be considered a dynamic reactive device per this standard. AEP would agree with the SDT that a synchronous condenser at an IBR facility should be considered a dynamic reactive device and requiring the desired monitoring. However, AEP would not agree to requiring monitoring "all" synchronous condensers in the transmission system under this SDT effort, and requests this be made clear in the Technical Rationale document. Please note that ERCOT already requires PMU monitoring at new FACTS devices and new synchronous condensers connected to 100kV and above.	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	
Document Name	
Comment	
Protection relays and most disturbance monitoring equipment does not record power quantities in the FR Comtrade records. The sequence, power, and frequency values can be calculated from the analog values that are recorded in 2.1.1 and 2.1.2. Will it be acceptable to provide a comtrade file with only the individual phase analog values which can be used to calculate the real and reactive power values?	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2021-04 Modifications to PRC-002 – Phase II | Draft 3
Comment Period Start Date:	5/31/2024
Comment Period End Date:	6/17/2024
Associated Ballot(s):	2021-04 Modifications to PRC-002 – Phase II Implementation Plan AB 3 OT 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 | Non-Binding Poll AB 3 NB 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 AB 3 ST 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll AB 3 NB 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 AB 3 ST

There were 61 sets of responses, including comments from approximately 144 different people from approximately 92 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, Soo Jin Kim (via email) or at (404) 446-9742.

Questions

1. Do you agree with the modification in “Applicability, Section 4.2. Facilities” in PRC-028-1 to remove “Non-BES Inverter Based Resources …”?

2. Do you agree with removing “Inverter Based Resources” and “IBR Unit” under Term(s) for Reliability Standards PRC-002-5 and PRC-028-1?

3. Do you agree with the standard drafting team removing Requirement R9 in Reliability Standard PRC-028-1 and adding it to the Implementation Plan since it is more like a process, not a Requirement?

4. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

5. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?

6. 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
Portland General Electric Co.	Brooke Jockin	1,3,5,6		Portland General Electric Co.	Brooke Jockin	Portland General Electric	1	WECC
					Dan Mason	Portland General Electric	6	WECC
					Ryan Olson	Portland General Electric	5	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,SPP RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC

					Elizabeth Davis	PJM	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Matt Goldberg	ISO New England	2	NPCC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
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
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC

					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
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
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
					Tyler Brun	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC

Company Services, Inc.					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
DTE Energy	Patricia Ireland	4		DTE Energy	Patricia Ireland	DTE Energy - Detroit Edison	4	RF
					Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	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
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
David Kiguel	Independent	7	NPCC
Joel Charlebois	AESI	7	NPCC
Joshua London	Eversource Energy	1	NPCC
Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
Chantal Mazza	Hydro Quebec	1,2	NPCC

					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	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
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Heather Harris	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC

					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the modification in "Applicability, Section 4.2. Facilities" in PRC-028-1 to remove "Non-BES Inverter Based Resources …"?

Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Industry comments show that the exact definition of Inverter Based Resource should be used, not the uncapitalized version that is currently in the PRC-028 draft, which is not bounded by the official definition. The footnote in the proposed standard is also an expansion of the NERC approved definition.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
TEPC agrees with EEI's comments regarding Section 4.2.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. Please see response to EEI's comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FE supports EEI Comments which state:

EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the "Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies." and "Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard." The Purpose statement is not intended to define or expand which facilities are to be applicable to a NERC Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.

We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.	
Richard Jackson - U.S. Bureau of Reclamation – 1	
Answer	No
Document Name	
Comment	
PRC-028 does not apply to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
AZPS supports the following comments that were submitted by EEI on behalf of its members: EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the "Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies." and "Purpose: The reliability	

outcome achieved through compliance with the Requirements of the Reliability Standard." The Purpose statement is not intended to define or expand which facilities are to be applicable to a NERC Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources. We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
We do not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unrestrained and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Also, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
No. Non-BES IBRs should be applicable to this standard, as it aligns with the FERC order activities and the on-going NERC Registration efforts to incorporate the non-registered BPS-connected IBRs that are owned/operated by the newly proposed Category 2 GO and GOP entities. Exclusion of these BPS-connected IBRs would significantly limit the ability to ensure that all BPS-connected IBRs have adequate data for performance evaluation/analysis during BPS/BES disturbances and data for BPS-connected IBR model validation.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The non-BES IBRs are re-introduced in the standard given that new registration criteria is now approved by FERC.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI’s comment.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
USV agrees with comments proposed by NPCC. The purpose of the project is to create a clear understanding of Non-BES and BES inverter-based resources and address gaps that exist in the current standards. With the proposed language, we foresee a lot of interpretation when it comes to inverter-based resources and note inconsistency between the three PRC standards. Suggest coordination between the three PRC standards that are currently open and progressively work towards the same or similar goal.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The non-BES IBRs are re-introduced in the standard given that new registration criteria is now approved by FERC. This SDT is closely working with SDTs of PRC-029 and PRC-030 standards.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
It is imperative that the standard drafting teams for this project as well as the 2020-02 (PRC-024 and PRC-029) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. Furthermore, this modification no longer addresses the purpose or goal of the IRPTF SAR as approved by the Standards Committee: "This SAR proposes to revise PRC-002-2 or create a new standard to address gaps within the existing standard. The goal is to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, **including in areas of the Bulk Power System (BPS) that may**	

not be covered by the existing requirements. Nor do these modifications address the recommendations of the IRPTF in the IRPTF Review of NERC Reliability Standards White Paper where "The IRPTF recommends **that a SAR(s) be developed** to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, **due to the continued growth of BPS-connected inverter-based resources**".	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. This SDT is working closely with PRC-029 and PRC-030 SDTs. The proposed standard strikes a balance between various opposing opinions from the industry, recommendations from NERC IRPTF and various disturbance reports, and FERC directives.	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	
It is imperative that the standard drafting teams for this project as well as the 2020-02 (PRC-024 and PRC-029) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. Furthermore, this modification no longer addresses the purpose or goal of the IRPTF SAR as approved by the Standards Committee: "This SAR proposes to revise PRC-002-2 or create a new standard to address gaps within the existing standard. The goal is to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, **including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements**. Nor do these modifications address the recommendations of the IRPTF in the IRPTF Review of NERC Reliability Standards White Paper where "The IRPTF recommends **that a SAR(s) be developed** to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, **due to the continued growth of BPS-connected inverter-based resources**".	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. This SDT is working closely with PRC-029 and PRC-030 SDTs. The proposed standard strikes a balance between various opposing opinions from the industry, recommendations from NERC IRPTF and various disturbance reports, and FERC directives.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Industry comments show that the exact definition of Inverter Based Resource should be used, not the uncapitalized version that is currently in the PRC-028 draft, which is not bounded by the official definition. The footnote in the proposed standard is also an expansion of the NERC approved definition.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM is in support and agreement of EEI comments.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. See response to EEI's comment.	
Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

NextEra Supports EEI Comments

EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the "Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies." and "Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard." The Purpose statement is not intended to define or expand which facilities are to be applicable to a NERC Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.

We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to ISO/RTO Council's comment.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	

Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) is concerned with the removal of non-BES inverter-based resources (IBRs) from Applicability, Section 4.2, particularly if non-BES IBRs will need to be added later. Although NERC has authority over the BPS, to the extent proposed PRC-028, Section 4.2 explicitly applies to BES IBRs only, then PRC-028 would not apply to BPS resources (i.e. registered non-BES IBRs). Several other NERC standards are relying on PRC-028 for monitoring. If PRC-028 doesn't require IBR monitoring as a foundational element, then the other IBR performance standards relying on PRC-028 will likely be less effective too. Therefore, the Applicability of PRC-028 should be expanded to apply to both BES IBRs and non-BES IBRs. Ultimately, adequate data must be available from IBRs to evaluate IBR ride-through performance during BES Disturbances and to provide data for IBR model validation.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The non-BES IBRs are re-introduced in the standard given that new registration criteria is now approved by FERC.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NextEra supports EEI's comments:

EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the "Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies." and "Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard." The Purpose statement is not intended to define or expand which facilities are to be applicable to a NERC Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources.

We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.

Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
It is imperative that the standard drafting teams for this project as well as the 2020-02 (PRC-024 and PRC-029) and 2023-02 (PRC-030 vs PRC-004) assure a coherent way of addressing the inclusion and exclusion of IBRs in current and upcoming standards. Furthermore, this modification no longer addresses the purpose or goal of the IRPTF SAR as approved by the Standards Committee: "This SAR proposes to revise PRC-002-2 or create a new standard to address gaps within the existing standard. The goal is to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, **including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements**. Nor do these modifications address the recommendations of the IRPTF in the IRPTF Review of NERC Reliability Standards White Paper where "The IRPTF recommends **that a SAR(s) be developed** to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, **due to the continued growth of BPS-connected inverter-based resources**".	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. This SDT is working closely with PRC-029 and PRC-030 SDTs. The proposed standard strikes a balance between various opposing opinions from the industry, recommendations from NERC IRPTF and various disturbance reports, and FERC directives.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review.	
Michael Johnson - Michael Johnson On Behalf of: 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	
Until NERC and industry sort out what will be included in NON-BES IBRs, we cannot have it written in a standard.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The non-BES IBRs are re-introduced in the standard given that new registration criteria is now approved by FERC.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	

This change adds clarity to the applicability of the standard	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF’s comment.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
AEPC signed on to ACES comments:	

ACES is very appreciative of the effort put forth by the SDT to listen to industry comments and revise PRC-028-1 accordingly. It is the opinion of ACES that removing “Non-BES Inverter Based Resources” is the correct approach for this draft; however, we do not completely agree with language chosen by the SDT for Section 4.2. We recommend the following language:

4.2.1 For the purposes of this standard, “inverter-based resources” refers to a collection of 1 (one) or more of any of the following facility types that operate as a single plant/resource:

4.2 Facilities: Elements associated with inverter-based resources meeting the criteria of Inclusion I4 of the BES definition.

4.2.1.1 Individual solar photovoltaic (PV)

4.2.1.2 Type 3 and Type 4 wind turbines

4.2.1.2 In the case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource includes the VSC HVDC line.

4.2.1.3 Battery energy storage system (BESS), or

4.2.1.4 Fuel cells

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.

Ruchi Shah - AES - AES Corporation - 5

Answer	Yes
Document Name	

Comment

AES CE supports MRO NSRF’s comment on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF’s comment.	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
LES supports MRO NSRF’s comment on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF’s comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
Thanks for taking time to review the draft standard.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the draft standard.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF requests additional information on the future process to be used to revisit PRC-028-1 once the Rule of Procedure IBR Registration changes are approved and the NERC Glossary of Terms are updated for new IBR definitions.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

SMUD agrees with the SDT's decision to remove "Non-BES Inverter Based Resources" from the applicable facilities in this new version of PRC-028-1; however, we are concerned that this may be a short-term fix since FERC Order 901 directs NERC to "submit, by November 4, 2024, new or modified Reliability Standards that require disturbance monitoring data sharing and post-event performance validation for **registered IBRs** [emphasis added]."

The term "registered IBRs" in FERC Order 901 includes BES IBRs registered with NERC and IBRs which will be registered according to FERC's IBR Registration Order. Once FERC approves the registration criteria proposed in NERC's rules of procedure changes submitted to FERC on March 19, 2024, the SDT will be required to modify PRC-028-1 again to include the non-BES IBRs that will be registered. This future change that would be required to PRC-028-1 is inefficient.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	
Comment	
NV Energy agrees with the removal of Non-BES inverter based resources, as long as this is the desired final state of the applicable facilities for this standard. However, NV Energy does not agree with moving the goal posts to obtain a desirable short-term outcome, if the intention is to revert back to the inclusion of Non-BES Inverter Based Resources at a later date.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI does not support the modifications to the Applicability Section. The definition for Inverter Based Resource (IBR) was approved by industry in April under Project 2020-06. We also do not agree with inserting the uncapitalized version of IBR into this section because it is unbounded and insufficient to identify the Facilities applicable to this Standard, as required in the Rules of Procedure (Appendix 3a, Standard Processes Manual). Moreover, the footnote included in the Purpose statement has the effect of expanding the meaning of the recently approved definition of IBR outside of the Applicability Section of this Standard. EEI notes that the Standards Processes Manual states that the "Applicability: Identifies the specific Functional Entities and Facilities to which the Reliability Standard applies." and "Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard." The Purpose statement is not intended to define	

or expand which facilities are to be applicable to a NERC Reliability Standard. To address this issue the Applicability Section of PRC-028 should be changed back to the capitalized version of Inverter Based Resources. We also note that Voltage Source Converters – High-voltage Direct Current (VSC-HVDC) were included in Requirement R1, subpart 1.4 but not specifically identified in the Applicability Section of PRC-028 or the approved SAR. EEI further notes that this project was approved to address issues surrounding the changing resource mix and the increased penetration of IBRs. If VSC-HVDC systems are subject to the same risks and concerns as IBRs, then the SAR should be modified and resubmitted with a technical justification clarifying why those resources need to be included in this Reliability Standard, in alignment with the Standard Processes Manual (Appendix 3a). While there is some information contained in the Technical Rationale, EEI does not believe this is sufficient to allow these resources to be added to this Standard.	
Likes 1	Mazza Chantal On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5;
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.	
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	
ACES is very appreciative of the effort put forth by the SDT to listen to industry comments and revise PRC-028-1 accordingly. It is the opinion of ACES that removing "Non-BES Inverter Based Resources" is the correct approach for this draft; however, we do not completely agree with language chosen by the SDT for Section 4.2. We recommend the following language: 4.2 Facilities: Elements associated with inverter-based resources meeting the criteria of Inclusion I4 of the BES definition. 4.2.1 For the purposes of this standard, "inverter-based resources" refers to a collection of 1 (one) or more of any of the following facility types that operate as a single plant/resource:	

4.2.1.1 Individual solar photovoltaic (PV) 4.2.1.2 Type 3 and Type 4 wind turbines 4.2.1.2 In the case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource includes the VSC HVDC line. 4.2.1.3 Battery energy storage system (BESS), or 4.2.1.4 Fuel cells	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the drafting team's simplification of the Applicability section.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the removal of Non-BES Inverter Based Resources. SIGE is concerned that the intention behind removing Non-BES Inverter Based Resources is only a short-term allowance until the Rules of Procedure changes are approved. While SIGE recognizes the challenges the Drafting Teams are facing; the parallel development of IBR-focused Standards and IBR definitions/rules of procedure may result in 'temporary' Standards that may not be fully aligned across their Applicability and Facilities sections. Meaning, it seems the current open drafts are being written as stop gaps until the IBR definitions and Rules of Procedure are approved rather than pausing to focus on the definitions and Rules of Procedure first then revise the Standards.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	

Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
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	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	

Jennifer Neville - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE is concerned removing "Non-BES Inverter Based Resources" from the Applicability Section 4.2 will eliminate all solar facilities with less than 75 MW of aggregated generation capacity from complying with this standard. In addition, storage facilities with less than 75 MW aggregated generation capacity would be excluded from this standard. This data is needed to have adequate data available from inverter-based resources to evaluate ride-through performance during BES Disturbances. Texas RE recommends the following verbiage (in bold):

4.2. Facilities

4.2.1 BES inverter-based resources

4.2.2 Non-BES inverter-based resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

This change would also facilitate the new GADS reporting for Solar facilities, which requires generating plants with a Plant Total Installed Capacity of 20 MW or greater per plant to submit the data.

Likes 0	
Dislikes 0	

Response

The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The applicability now also includes non-BES IBRs given that new registration criteria is now approved by FERC.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment

N/A

Likes 0	

Dislikes 0	

Response
Thanks for taking time to review the draft standard.

2. Do you agree with removing "Inverter Based Resources" and "IBR Unit" under Term(s) for Reliability Standards PRC-002-5 and PRC-028-1?	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
These definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC "directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
The SRC disagrees with the removal of these terms from the standards. One of the benefits of developing formal definitions for IBR and IBR Unit in Project 2020-06 is that these terms, once finalized, will provide a consistent understanding of what constitutes an IBR and an IBR Unit for purposes of NERC Reliability Standards. However, developing IBR-focused standards that explicitly decline to use these standardized definitions undermines the benefits of developing Glossary-level definitions, and presents a risk that different standards will use different definitions of what constitutes an IBR, resulting in an inconsistent, difficult-to-comply-with patchwork of regulations rather than a consistent suite of IBR-related Reliability Standards. The draft 2 postings effectively explained the overlap with the work being done in Project 2020-06	

so that entities could evaluate PRC-002 and PRC-028 in light of those definitions. The SRC recommends that the drafting team revise PRC-002 and PRC-028 to once again rely on the Project 2020-06 definitions of IBR and IBR Unit to help ensure consistency across IBR-related standards on the front end and avoid the need to make subsequent revisions to these standards once Project 2020-06 is complete. The SRC believes that a decision not to use the Project 2020-06 definitions should be supported by a compelling justification.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to IRC SRC’s comment.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No

Document Name	
Comment	
The voters in Project 2020-06, Inverter-based Resource Glossary Terms draft #2, approved the definition of IBR on April 8, 2024, which is different than the definition proposed in Footnote 1 of PRC-028-1. Using the term “inverter-based resources” and defining it with Footnote 1 is inefficient and would create two definitions for the same resource. The SDT of PRC-028-1 should coordinate with the SDT of Project 2020-06 and NERC staff to ensure the definition of IBR and new PRC-028-1 are submitted to FERC simultaneously thereby eliminating another ballot for PRC-028-1 to add the NERC Glossary Term for IBR into the standard.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	
These definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC “directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS.”	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
These definitions are the foundation of several ongoing projects in response to FERC Order 901, where FERC “directs NERC to submit new or modified Reliability Standards that address specific matters pertaining to the impacts of IBRs on the reliable operation of the BPS.”	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
USV agrees with comments proposed by NPCC.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NPCC’s comment.	

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
No. Removing these two Terms is not aligned with the other on-going IBR standard related work throughout NERC. By removing these two Terms, it appears to have forced the creation of a new definition of “inverter-based resources” under Footnote 1 of this draft of PRC-028-1. It seems counter productive to have a unique definition of IBRs and IBR units under each different NERC standard. Having all standards aligned to the same core definitions/terms for IBRs will make all this standard development work, execution of the standards, and compliance activities more efficient for all entities involved.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro appreciates the drafting team's efforts and opportunity to comment, and offers the following. BC Hydro prefers that PRC-028-1 rely on an IBR definition, we understand the rationale for moving ahead while the definitions being drafted by the Project 2020-06 drafting team are being finalized.	

BC Hydro requests that the drafting team clarify that the Footnote 1 is not intended to expand on the applicability scope of PRC-028-1, which does not include reactive power devices providing reactive support, such as STATCOMs as an example. BC Hydro suggests that the Footnote 1 be (a) referenced within the Section 4.2 Facilities of PRC-028-1, and (b) revised to include a provision that IBRs are devices capable of exporting Real Power as follows. Suggested revision to Footnote 1 – For the purpose of this standard, “inverter-based resources” refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource and can export Real Power from a primary energy source or energy storage system via a power electronics interface (such as an inverter or converter), and that is/are operated as a single resource connected to the electric power system at a common point of connection.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. See Technical Rationale provided with IBR definition to understand what is and is not an IBR.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy's response should be Yes. Noting the term IBR was defined under Project 2020-06, received favorable ballot by the industy but is pending final approval by the NERC BoT and FERC, FE does support removing these under Term(s)	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
Inverter-based resource is included in the “**Purpose**” of PRC-028-1 and should be included in the Term(s) section.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
NextEra supports EEI's comments: EEI supports removing Inverter Based Resources and IBR Unit under the Terms section of PRC-002-5 and PRC-028-1, noting that the term IBR was defined under Project 2020-06, received a favorable ballot by the industry and is now pending final approval by the NERC BOT and FERC.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with removing Inverter Based Resources (IBR) and IBR Unit as IBR Unit is unapproved and IBR refers to IBR Unit. Please add a Standard-specific definitions section like PRC-005-6 that addresses the inverter-based resources definition in Footnote 1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. See response to EEI’s comment.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI’s comment.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the removal of the as of yet unapproved terms “Inverter Based Resources” and “IBR Unit”.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF	

Answer	Yes
Document Name	
Comment	
NextEra Supports EEI's comments: EEI supports removing Inverter Based Resources and IBR Unit under the Terms section of PRC-002-5 and PRC-028-1, noting that the term IBR was defined under Project 2020-06, received a favorable ballot by the industry and is now pending final approval by the NERC BOT and FERC.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports removing Inverter Based Resources and IBR Unit under the Terms section of PRC-002-5 and PRC-028-1, noting that the term IBR was defined under Project 2020-06, received a favorable ballot by the industry and is now pending final approval by the NERC BOT and FERC.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees with the practice of not using unapproved defined terms in Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company would like more information on the plan to reintroduce the inverter data.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Based on received industry comments, requirement for IBR unit SER data is reintroduced in the standard. However, to strike a balance between various opposing opinions, FR data is required from collector feeder breakers in lieu of IBR units.	
Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	Yes

Document Name	
Comment	
PNM is in support and agreement of EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI comments.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Support removal of the above terms from the standards PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI’s comment.	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
LES supports MRO NSRF’s comment on this question.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	

Answer	Yes
Document Name	
Comment	
The definition needs to be in the glossary of terms	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Michael Johnson - Michael Johnson On Behalf of: 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	
Until industry and NERC DTs pass definitions, they should not be used in other standards with a capital letter. If DT needs to use lower case inverter based resource they must stipulate which ones they mean, which this draft has a footnote doing.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	

Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Reclamation agrees that these identifiers should be in the NERC Glossary of Terms and not in the standards themselves.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Tri-State agrees with the removal of unapproved defined terms in the standard. However, if the intention is that the definitions will be added at a later date when they are approved then the SDT should not include the footnote and wait until the definitions are approved through ballot. It seems like we are putting the "cart before the horse" by not having the IBR definitions approved first and working on the related standards just to meet a deadline. It will make it a duplicate process to have to come back to PRC-028 and comment/ballot again when the definitions are added.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Support removal of the above terms from the standards PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
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	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	

Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE continues to support Project 2020-06 to define Inverter-based Resource and Inverter-based Resource Unit in the NERC Glossary. Texas RE encourages the various IBR drafting teams to maintain consistent footnote description(s) of inverter-based resources in various proposed standards or standard revisions pertaining to IBRs.	
Likes 0	
Dislikes 0	

Response
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.

3. Do you agree with the standard drafting team removing Requirement R9 in Reliability Standard PRC-028-1 and adding it to the Implementation Plan since it is more like a process, not a Requirement?	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State agrees with MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comments.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
PRC-028 does not apply to Reclamation	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review these standards.	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy does not agree with the Implementation Plan section information titled “Process for Seeking an Extension from Compliance Dates”. Instead, we suggest the Standard follow existing Corrective Action Program (CAP) program guidance already in practice with other NERC Standards.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The section titled “Process of seeking an extension from compliance dates” is revised to add clarity.	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO NSRF’s comment on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF’s comment.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No

Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees to removing R9. However, Southern Company **does not agree** to requiring RE approval of an extension plan. Some criteria should be provided in the implementation plan which will permit extension in cases where the procurement and/or installation of designated additional DME is beyond the control of the entity required to install the DME.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The extension of compliance date would be beyond timeline allowed by FERC directive. Hence, some oversight by compliance enforcement agency is necessary. Note that the "regional entity" is replaced with "compliance enforcement agency" along with some other clarifying revisions.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District,	

3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD agrees with the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy agrees with removing R9 and with the concept of placing the "Process for Seeking an Extension from Compliance Dates" in the implementation Plan. However, there should be no requirement for the GO or TO to seek approval from the Regional Entity. NV Energy recommends that the SDT create clear and auditable criteria that if met, allows for the extension of compliance dates. GOs and TOs would submit notification to the Regional Entity that they will require an extension to the compliance dates, based on the met criteria. The Regional Entities' role would be to ensure that the proper criteria are indicated by the GO or TO to allow for an extension of compliance dates, rather make subjective decisions on approval of requests. This would also eliminate concerns about differences between regions in allowing for extensions.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The extension of compliance date would be beyond timeline allowed by FERC directive. Hence, some oversight by compliance enforcement agency is necessary. Note that the “regional entity” is replaced with “compliance enforcement agency” along with some other clarifying revisions.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Support removal of R9 from PRC-028-1 and move to the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with this change to R9.	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
We do not support sub-Requirement 9.5 about submitting a Corrective Action Plan to the Regional Entity upon requesting a time extension for compliance. Request that the Drafting Team (DT) consider defining the criteria/process for the Regional Entity to follow for evaluating compliance time extensions.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The extension of compliance date would be beyond timeline allowed by FERC directive. Hence, some oversight by compliance enforcement agency is necessary. Note that the “regional entity” is replaced with “compliance enforcement agency” along with some other clarifying revisions.	
Michael Johnson - Michael Johnson On Behalf of: 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	
Yes, this felt more like an implementation plan than a Requirement. PGAE agrees with the DT making this change	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
This approach is inconsistently applied across the standards but we are indifferent as to the appropriate location for corrective action plans.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comment.	
Daniel Gacek - Exelon - 1	

Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
AES CE agrees that moving this language to the Implementation Plan makes sense but is concerned that the "circumstances beyond its control" language is vague and open to interpretation. Additional criteria or qualifications to evaluate individual circumstances should be included.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Following statement is added to the implementation plan: Circumstances beyond the entity's control may include supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside the entity's control.	
Kinte Whitehead - Exelon - 3	

Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports moving the proposed PRC-028-1 Requirement R9 to the implementation plan. The NAGF does not support sub-Requirement 9.5 with regard to submitting a Corrective Action Plan to the Regional Entity upon requesting a time extension for compliance. Request that the Drafting Team (DT) consider defining the criteria/process for the Regional Entity to follow for evaluating compliance time extensions.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The extension of compliance date would be beyond timeline allowed by FERC directive. Hence, some oversight by compliance enforcement agency is necessary. Note that the “regional entity” is replaced with “compliance enforcement agency” along with some other clarifying revisions.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI’s comment.	
Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM is in support and agreement of EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI’s comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that Requirement R9 is better placed in the Implementation Plan than in the Requirements of PRC-028-1.	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
NextEra supports EEI's Comments: EEI agrees that Requirement R9 is better placed in the Implementation Plan than in the Requirements of PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the removal of R9 from the standard and its placement in the Implementation Plan.	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	

Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the removal of Requirement R9 from PRC-028-1 and adding it to the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
NextEra supports EEI's comments: EEI agrees that Requirement R9 is better placed in the Implementation Plan than in the Requirements of PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks 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	
Thanks for your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	
Thanks for your support.	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review draft standards.	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	
Abstain.	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review draft standards.	

4. Do you agree with the Implementation Plan for revised PRC-002-5 and new Standard PRC-028-1?

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	No
Document Name	
Comment	

All IBRs that enter commercial operation after the effective date of the standard should be required to comply with the PRC-028 no later than 15 months after the effective date of the standard. IBRs that have a commercial operations date more than 15 months after the effective date of the standard should be required to be compliant on their first day of commercial operation. Such facilities should be constructed to meet the requirements of the standard, and should not be eligible to operate without being compliant for 15 months after they are in commercial operation. This should be clarified in the Implementation Plan as detailed below:

Compliance Date for PRC-028-1 Requirements R1-R7 (page 3)

"For inverter-based resources facilities entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or by the commercial operation date, whichever is earlier later."

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Examples are added in the Implementation Plan to clarify timeline for IBRs entering commercial operation after the effective date of PRC-028.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	

Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to IRC SRC's comment.	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
It's unclear what happens if the extension is denied?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Considering other industry comments on this topic, revisions are made to the Implementation Plan.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO agrees with the majority of the implementation plan but still has concerns with the "15 calendar months following the effective date of the standard" requirement for inverter-based resources entering commercial operation after the effective date, and believes that more	

time is needed to properly budget, modify designs and procure equipment for projects already under development. NIPSCO proposes modifying the following language: For inverter-based resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within “36 calendar months following the effective date of the standard or by" the commercial operation date, whichever is later.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT believes that 15 calendar months is adequate time to install disturbance monitoring equipment at plants under development currently.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy agrees with the proposed compliance dates; however, NV Energy does not agree with the proposed “Process for Seeking an Extension from Compliance Dates” (see response to question 3.) The implementation plan requires compliance 15 calendar months after the effective date or the commercial operation date whichever is later. The WebEx discussed that facilities in commercial operation beyond the 15 months after the effective date must be compliant on the first day of commercial operation. The language should be clarified since this is an important detail.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Examples are added in the Implementation Plan to clarify timeline for IBRs entering commercial operation after the effective date of PRC-028.	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
It is unclear if the implementation plan compliance due date for facilities reaching COD after the effective date of PRC-028 is meant to be absolutely 15 months after the effective date of PRC-028. Given that IBRs in commercial operation on or before the effective date is previously prescribed (50% within 3 calendar years and 100% by 1/1/2030), IBRs entering CO after the effective date should just be 15 calendar months and not include "whichever is later."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Examples are added in the Implementation Plan to clarify timeline for IBRs entering commercial operation after the effective date of PRC-028.	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the North American Generator Forum (NAGF) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to comment submitted by MRO NSRF and NAGF.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Six years would be a sufficient amount of time to plan and budget for the procurement and installation of the DDR equipment barring any supply chain complications or any other delays. USV recognizes the FERC directive mandating completion by 1/1/2030, however, due to many of the IBR sites having strict language when dealing with manufacturer's warranty and having to rely on third parties, it may result in additional complications that could delay the installation and setting up of this highly specialized equipment. We recommend that the implementation period be changed to 6 years from the effective date of the standard as opposed to targeting the date of January 1, 2030.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. In Order No. 901, FERC directed the development of Reliability Standards to address IBR disturbance monitoring requirements by November 4, 2024. Further, FERC directed that all of the Reliability Standards developed under that order, including Reliability Standards to address IBR disturbance monitoring data, be “effective and enforceable well in advance of 2030.” Order No. 901 at P 226. Since the initial posting of proposed PRC-028-1 in August 2023, the drafting team recognized that the proposed standard is expected to have wide ranging impacts on entities as many will be installing disturbance monitoring equipment on their IBRs for the first time. The drafting team also considered stakeholder feedback regarding the challenges that entities may face in implementing the standard across an entire fleet. However, FERC’s direction in Order No. 901 is clear: all requirements that address directives from Order No. 901 must be implemented by 2030 at the latest. Further, a large majority of these requirements rely on installed and functioning IBR disturbance monitoring equipment. All delays implementing proposed PRC-028-1 will impact the ability to effectively comply with other Order No. 901 related requirements. The proposed compliance extension process is intended to provide a “relief valve” for entities in the event they are unable to comply with the standard’s requirements due to circumstances beyond their control. Under this process, entities would explain the circumstances precluding a timely implementation and would receive an extension from the compliance date, and the ERO would maintain its reliability oversight. In response to your comment and others, the drafting team has included further explanation of the circumstances that may warrant an extension from the compliance date. These circumstances may include supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside the entity’s control. The drafting team also replaced “Regional Entity” with “Compliance Enforcement Authority” to leave maximum flexibility. The drafting team expects that NERC (or authorities in non-U.S. jurisdictions) will provide more guidance on how/where to submit requests closer to the effective date.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF agrees with the Implementation Plan for PRC-002-5. The NAGF believes that the proposed 3-year Implementation Plan for PRC-028 is not enough time for installing new data monitoring equipment. Therefore, recommend that the DT consider a 5-year Implementation Plan for PRC-028-1.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. In Order No. 901, FERC directed the development of Reliability Standards to address IBR disturbance monitoring requirements by November 4, 2024. Further, FERC directed that all of the Reliability Standards developed under that order, including Reliability Standards to address IBR disturbance monitoring data, be “effective and enforceable well in advance of 2030.” Order No. 901 at P 226.

Since the initial posting of proposed PRC-028-1 in August 2023, the drafting team recognized that the proposed standard is expected to have wide ranging impacts on entities as many will be installing disturbance monitoring equipment on their IBRs for the first time. The drafting team also considered stakeholder feedback regarding the challenges that entities may face in implementing the standard across an entire fleet.

However, FERC’s direction in Order No. 901 is clear: all requirements that address directives from Order No. 901 must be implemented by 2030 at the latest. Further, a large majority of these requirements rely on installed and functioning IBR disturbance monitoring equipment. All delays implementing proposed PRC-028-1 will impact the ability to effectively comply with other Order No. 901 related requirements.
The proposed compliance extension process is intended to provide a “relief valve” for entities in the event they are unable to comply with the standard’s requirements due to circumstances beyond their control. Under this process, entities would explain the circumstances precluding a timely implementation and would receive an extension from the compliance date, and the ERO would maintain its reliability oversight.
In response to your comment and others, the drafting team has included further explanation of the circumstances that may warrant an extension from the compliance date. These circumstances may include supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside the entity’s control.

The drafting team also replaced "Regional Entity" with "Compliance Enforcement Authority" to leave maximum flexibility. The drafting team expects that NERC (or authorities in non-U.S. jurisdictions) will provide more guidance on how/where to submit requests closer to the effective date.	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO NSRF's comment on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES CE believes that the new implementation plan language for PRC-028 around requiring compliance 15 calendar months after the effective date or the commercial operation date, whichever is later, needs to be revised. During the Webinar the SDT discussed that facilities in commercial operation beyond the 15 months after the effective date must be compliant on the first day of commercial operation. The language should be updated to clearly reflect this intention.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. Examples are added in the Implementation Plan to clarify timeline for IBRs entering commercial operation after the effective date of PRC-028.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Under the "Compliance Date for PRC-028-1 Requirements R1-R7" section, modify the following language: For inverter-based resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within "three (3) calendar years" following the effective date of the standard or the commercial operation date, whichever is later.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The SDT believes that 15 calendar months is adequate time to install disturbance monitoring equipment at plants under development currently.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
The proposed 3-year Implementation Plan for PRC-028 is not enough time for installing new data monitoring equipment. Therefore, recommend that the DT consider a 5-year Implementation Plan for PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In Order No. 901, FERC directed the development of Reliability Standards to address IBR disturbance monitoring requirements by November 4, 2024. Further, FERC directed that all of the Reliability Standards developed under that order, including Reliability Standards to address IBR disturbance monitoring data, be “effective and enforceable well in advance of 2030.” Order No. 901 at P 226. Since the initial posting of proposed PRC-028-1 in August 2023, the drafting team recognized that the proposed standard is expected to have wide ranging impacts on entities as many will be installing disturbance monitoring equipment on their IBRs for the first time. The drafting team also considered stakeholder feedback regarding the challenges that entities may face in implementing the standard across an entire fleet. However, FERC’s direction in Order No. 901 is clear: all requirements that address directives from Order No. 901 must be implemented by 2030 at the latest. Further, a large majority of these requirements rely on installed and functioning IBR disturbance monitoring equipment. All delays implementing proposed PRC-028-1 will impact the ability to effectively comply with other Order No. 901 related requirements.	

The proposed compliance extension process is intended to provide a "relief valve" for entities in the event they are unable to comply with the standard's requirements due to circumstances beyond their control. Under this process, entities would explain the circumstances precluding a timely implementation and would receive an extension from the compliance date, and the ERO would maintain its reliability oversight. In response to your comment and others, the drafting team has included further explanation of the circumstances that may warrant an extension from the compliance date. These circumstances may include supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside the entity's control. The drafting team also replaced "Regional Entity" with "Compliance Enforcement Authority" to leave maximum flexibility. The drafting team expects that NERC (or authorities in non-U.S. jurisdictions) will provide more guidance on how/where to submit requests closer to the effective date.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation supports an 18-month implementation time frame.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT believes that 15 calendar months is adequate time to install disturbance monitoring equipment at plants under development currently.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	

Comment	
NextEra supports EEI's comments: EEI supports the proposed Implementation Plan for both PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the simplification of the Implementation Plan for inverter-based resources entering commercial operation after the effective date of the standard.	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
NextEra supports EEI's comments: EEI supports the proposed Implementation Plan for both PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed Implementation Plan for both PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Alison MacKellar - Constellation - 5	

Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Michael Johnson - Michael Johnson On Behalf of: 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	
Phased implementation is reasonable and PGAE understands the 01 January 2030 100% requirement is in line with FERC 901, not the DT's timeline.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy supports the Implementation Plan for PRC-002-5 and PRC-028-1	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Support the implementation plans for both PRC-002-5 and PRC-028-1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Jennifer Neville - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks 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	
Thanks 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	
Thanks for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends maintaining the previous verbiage of the implantation plan for the Compliance Date for PRC-028-1 Requirements R1 – R7: “Entities shall comply with Requirements R1 through R7 at 50% of **their generating plants/Facilities** within three calendar years of the effective date…” If it is changed to inverter-based resources, it is unclear how to comply with 50%. The description of inverter-based resource in Footnote 1 in PRC-028-1 appears to contradict the language of R1. The footnote description of IBR is at the collector level while Requirement R1 refers to	

the Point of Interconnection (POI). The implementation plan should be at the Point of Interconnection to be clear what is needed to comply with R1. Additionally, Texas RE recommends the header on page 3 say "Process for **Requesting** an Extension to Compliance Dates." Instead of "Process for Seeking an Extension from Compliance Dates."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Based on other industry comment, the standard refers to proposed definition of Inverter-Based Resource. Per definition, the IBR is a plant/facility. The header on Page 3 is revised as suggested.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC aggrees with the majority of the implementation plan but still has two concerns that were voiced in our prior comments. First: the use of the term "beyond control" is ambiguous. Who gets to determine what is "beyond control?" Second: It is unclear if a Regional Entity has the authority to grant a compliance waiver. Clarification is necessary.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. In Order No. 901, FERC directed the development of Reliability Standards to address IBR disturbance monitoring requirements by November 4, 2024. Further, FERC directed that all of the Reliability Standards developed under that order, including Reliability Standards to address IBR disturbance monitoring data, be “effective and enforceable well in advance of 2030.” Order No. 901 at P 226.

Since the initial posting of proposed PRC-028-1 in August 2023, the drafting team recognized that the proposed standard is expected to have wide ranging impacts on entities as many will be installing disturbance monitoring equipment on their IBRs for the first time. The drafting team also considered stakeholder feedback regarding the challenges that entities may face in implementing the standard across an entire fleet.

However, FERC’s direction in Order No. 901 is clear: all requirements that address directives from Order No. 901 must be implemented by 2030 at the latest. Further, a large majority of these requirements rely on installed and functioning IBR disturbance monitoring equipment. All delays implementing proposed PRC-028-1 will impact the ability to effectively comply with other Order No. 901 related requirements.

The proposed compliance extension process is intended to provide a “relief valve” for entities in the event they are unable to comply with the standard’s requirements due to circumstances beyond their control. Under this process, entities would explain the circumstances precluding a timely implementation and would receive an extension from the compliance date, and the ERO would maintain its reliability oversight.

In response to your comment and others, the drafting team has included further explanation of the circumstances that may warrant an extension from the compliance date. These circumstances may include supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside the entity’s control.

The drafting team also replaced “Regional Entity” with “Compliance Enforcement Authority” to leave maximum flexibility. The drafting team expects that NERC (or authorities in non-U.S. jurisdictions) will provide more guidance on how/where to submit requests closer to the effective date.

5. Do you agree the modifications made in PRC-002-5 and new Standard PRC-028-1 are cost effective?	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
PRC-028 will result in costs that were not previously budgeted for. There will be a large cost to retrofit legacy equipment for monitoring and also costs for the new communications. You will also have to bring on new staff to monitor, track and maintain.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive.	
Michael Johnson - Michael Johnson On Behalf of: 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	No
Document Name	
Comment	
No comment, PGAE does not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
The cost to install FR and DDR capabilities is not value added given how the information will be utilized (rarely or never)	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. The PRC-028/s purpose is different compared to PRC-002 purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF’s comments.	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments: It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement. As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address inverter-based resources; however, we disagree with making this new standard inclusive of all BES inverter-based resources regardless of risk to the BES. In the opinion of ACES, a blanket approach requiring every BES inverter-based resource to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which inverter-based resources pose the biggest risk to the BES, and where disturbance monitoring and reporting would provide the most benefit to the BES, **before selectively** adding such capabilities. In summary, it is our recommendation that PRC-028-1 take a similar *risk-based approach as is done in PRC-002-5.*	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment	
No. The standard requires IBR owners to have a robust compliance program implemented as well as event data collection process in place. However, this version of the standard removed the requirement for any IBR Unit to have SER, FR, or DDR data in an entire IBR plant. This will not help any event analysis process as it will not allow adequate analysis of an IBR facility's abnormal performance. At a minimum, fault codes should be available from every single IBR Unit within the facility. Lack of comprehensive data has significantly affected the ERO Enterprise's ability to conduct event analysis at many facilities over the past 7 years, as reported in numerous disturbance reports. The proposed standard would lead to inadequate data available at the inverter-level to do any useful event analysis and model validation, possibly leading to ongoing inconclusive root cause analyses. This would therefore not be cost effective for the industry. In addition, new IBRs being installed today and going forward will have all the SER, FR, and DDR data capabilities included in their inverters already, which means if the standard doesn't require this data set for these inverters/resources it could result in significant underutilization of the full capabilities of this equipment to ensure they operate reliably on the BPS.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SER data requirement for IBR units is restored. In lieu of FR data from IBR units, FR data from collector feeder breakers is required.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES CE believes this is not a cost effective approach to meet FERC Order 901. The requirements should be based on some study criteria similar to PRC-002 to identify specific generators that impacts reliability and therefore must invest this capital in order to ensure the reliability of the BES. AES CE recommends that the SDT leverage the expertise of Project Finance SMEs at the entities to understand the feasibility of implementing this new Standard, and the potential impacts to reliability that these additional costs could incur.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO NSRF's comment on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comments.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
The modifications to the present version of PRC-028-1 are less costly than the previous version; however, PRC-028-1 overall is not cost-effective. PRC-002 methodology for selecting BES buses that require (SER) and (FR) Data would be more appropriate and cost-effective than	

the present method for PRC-028. Requiring the TO and RC to identify areas that are susceptible to disturbances or have a large concentration of IBRs would benefit from DME capabilities. This would target the investment in the areas that need it most. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
The modifications to the present version of PRC-028-1 are less costly than the previous version; however, PRC-028-1 overall is not cost-effective. PRC-002 methodology for selecting BES buses that require (SER) and (FR) Data would be more appropriate and cost-effective than the present method for PRC-028. Requiring the TO and RC to identify areas that are susceptible to disturbances or have a large concentration of IBRs would benefit from DME capabilities. This would target the investment in the areas that need it most. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF notes that requiring data monitoring equipment at all IBR facilities is unnecessary and an excessive cost burden for existing IBR facility owners to bear which may lead to unintended adverse impacts to reliability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.	

Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Under the applicability of PRC-002, there is a process to identify the need to have FR, SER, and/or DDR capabilities. However, PRC-028 requires any GO/TO with BES inverter-based resources to have similar if not more stringent requirements for all BES inverter-based resources.	

For PRC-002, it is the responsibility of TOs and RCs to identify which BES elements are required to have this recording capability. Why should PRC-028, which is meant to be similar in purpose to PRC-002, be any different. We would like to understand the reliability benefit of including all BES IBR's rather than using a qualifying process like PRC-002 does with Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the North American Generator Forum (NAGF) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF and MRO NSRF's comments.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No

Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comments.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

PRC-028-1 will result in costs that were not previously required. These costs are not simply for the design and implementation of the monitoring but also for new communications infrastructure for legacy locations or compliance related staff to monitor, track and maintain compliance where it was not required before. For those owners that stream PMU data this standard could add significant communications costs to upgrade older facilities.

These following two comments relate to possible greatly increased costs for benefits that are not necessarily effective:

A) requiring SER on breaker positions on the GSU, collector buses and feeders, shunt devices, and AC-DC/DC-AC converters seems excessive. This quantity of monitored elements could require multiple DDRs depending on location and wiring.

B) Typically, fault recording is put on either the high side or low side of the GSU, not both. Requiring both could require multiple DDRs depending on location and wiring.

We suggest that the SDT consider requiring the DME on new (future) IBR facilities rather than applying this requirement retroactively. Including this data collection at the inverter level (for some of the inverters at the IBR facility) may prove to be beneficial for analyzing reactions of IBR facilities to transmission system disturbances. Provisioning the facility to include this data collection is much easier to accomplish during the design and construction phase of the facility.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

PRC-028-1 will result in costs that were previously not required.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
PRC-028-1 will result in costs that were not previously required. These costs are not simply for the design and implementation of the monitoring but also for new communications infrastructure for legacy locations or compliance related staff to monitor, track and maintain compliance where it was not required before. For those owners that stream PMU data this standard could add significant communications costs to upgrade older facilities. The reliability benefit of installing, maintaining, and operating monitoring capabilities on existing equipment does not justify the cost. However, NV Energy does agree that requiring monitoring capabilities on new equipment moving forward may be a cost-effective method to assist in addressing the issues set forth in the SAR and NERC Reports.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
It is ACES' opinion that the proposed changes to PRC-002 are minimal and therefore should have little to no cost to implement.	

As for the proposed PRC-028-1, we agree with the approach taken by the SDT to create a new Standard to specifically address inverter-based resources; however, we disagree with making this new standard inclusive of all BES inverter-based resources regardless of risk to the BES.

In the opinion of ACES, a blanket approach requiring every BES inverter-based resource to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which inverter-based resources pose the biggest risk to the BES, and where disturbance monitoring and reporting would provide the most benefit to the BES, before selectively adding such capabilities.

In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach as is done in PRC-002-5.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has a concern that the drafting team didn't provide any viable evidence in reference to cost effectiveness. The implementation Plan mentions the various stages of implementing the requirements for PRC-028, however, there are no actual numbers to support the effort and/or determine if either standard address cost effectiveness or not.

SPP recommends that the drafting team provides some type of cost analysis to support their efforts to determine if both standards address cost effectiveness.

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT is aware of cost burden of implementing PRC-028. The proposed standard hopes to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and FERC directive. Also, note that the purpose of PRC-028 is very different from PRC-002's purpose. The FR and DDR data collected at IBRs is expected to be used to show compliance with PRC-029 and for performance analysis under PRC-030.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FE finds not objections or concerns to the cost effectiveness of these proposals.	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Reclamation agrees with the PRC-002-5 cost effectiveness but PRC-028 does not apply to Reclamation	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
It is not possible to determine cost effectiveness. Can neither agree nor disagree.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC leave the consideration of cost effectiveness to the applicable entities.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	
MRO is not able to fully evaluate the cost effectiveness of the modification. However, the recent significant modifications to PRC-002 and PRC-028 have enhanced their cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	

Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy supports proposed EEI language for Question 5.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI’s comment.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	

Ameren has no comment on cost effectiveness of this project.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	
It is not possible to determine cost effectiveness. Can neither agree nor disagree.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	
Document Name	
Comment	
N/A - PNM has not performed a cost effective study.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment.	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	
Abstain from comment	
Likes 0	
Dislikes 0	
Response	
Thanks.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	

6. Provide any additional comments for the standard drafting team to consider, if desired.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	
Invenergy thanks the drafting team for their work and the opportunity to provide comments. Invenergy has concerns regarding R7.1. and the 20 calendar day data retention requirement for SER, FR, and DDR data. The Technical Rationale for PRC-028-1 states that, “With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable.” However, PRC-028-1 will apply to many existing inverter-based resources, some of which have been operational for decades and may possess legacy equipment incapable of storing data for such an extended period of time. Invenergy proposes the below modifications to R7.1.: 7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded. 7.1.1. If the recording equipment is incapable of storing 20 calendar days of data due to storage constraints, then data shall be retrievable for the maximum allowable period supported by the storage capabilities of the recording equipment, but not less than 10 calendar days.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT realized that in some cases, equipment at some existing IBRs, might need to be replaced to meet requirements of PRC-028. As such, the implementation plan allows appropriate time for existing IBRs. The justification for 20 calendar days retrievability is included in the technical rationale.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	

Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) is providing the following additional comments: **Purpose Statement** comments: SIGE does not support the use of Footnote 1 in the Purpose Statement. If the "inverter-based resource" definition/Footnote 1 referenced in the Purpose Statement is intended to be specific to PRC-028, then a Standard definition section should be included in PRC-028 and the "inverter-based resource" definition/Footnote 1 should be moved to the definition section (see PRC-005-6 for reference). **R1.2 comments:** SIGE requests removal of "including collector feeder breakers" from R1.2 as the inclusion of collector feeder breakers has the potential to include non-BES elements.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. To understand IBR plant's performance during system disturbances, data from collector system is necessary. As such, SER data from IBR units and collector feeder breakers is required. In lieu of FR data from IBR units, FR data from collector feeder breakers is specified.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI Comments	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. See response to EEI comment.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2024	
Answer	
Document Name	
Comment	

The SRC submit four additional comments/requests:

1) Reinstate the language "at least one IBR unit" in the PRC-028 requirements.

2) Reinstate inverter-level requirements in PRC-028 and to all future IBR installations

3) Update the associated Technical Rationale with justification for not including past recommendations into PRC-028

4) Continuing concern from last comment period regarding DDR coverage

The SRC disagrees with the modifications made to remove the "at least one IBR Unit" language from the PRC-028 requirements.

Based on NERC's Reliability Guideline entitled, *BPS-Connected Inverter-Based Resource Performance,* our understanding is that having IBR Unit level data is critical when investigating events. This recommendation was later reiterated in a 2nd NERC Reliability Guideline entitled, *Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*. Therefore, we see the removal of this requirement as problematic. We would like to see the "at least one IBR Unit" language added back in all applicable requirements, i.e., Parts 1.2, 1.3, 2.2. and 3.2.

The SRC requests inverter-level requirements be reinstated in PRC-028 and applied to all future IBR installations, at a minimum.

In September 2018, following unexpected performance of several large IBR plants during disturbances, NERC issued a Reliability Guideline entitled, *BPS-Connected Inverter-Based Resource Performance.*

{C}o This guideline contains a section (Chapter 6) dedicated to measurement data and performance monitoring. Within this section are "individual inverter level data" functional requirements.

{C}o The NERC guidance considers the need for inverter-level data to diagnose performance under certain types of events. For instance, the SRC understands partial tripping of plants, where only certain inverters persistently trip during events, to be a common issue.

In September 2019, NERC issued a second Reliability Guideline that again highlighted the need for inverter-level data, stating: "Data should be available from multiple sources to provide sufficient clarity as to any abnormal response or behavior within the plant. This includes plant control settings and static values, plant supervisory control and data acquisition data, sequence of events recording data, dynamic disturbance recorder data, and inverter fault codes and inverter-level dynamic recordings."

At least one ISO/RTO has modified its Generator Interconnection Agreement (GIA) to require inverter-level data (see current version of MISO's tariff

However, now that PRC-028 is diverging from prior NERC guidance and lowering the bar on monitoring requirements, the latest draft of PRC-028 appears to be inconsistent with NERC recommendations and reliability needs. Therefore, the SRC requests the SDT reinstate IBR Unit level requirements in PRC-028 to align with NERC Reliability Guideline recommendations.

Moreover, PRC-028 provides the foundation for monitoring performance that will be relied upon across NERC standards to validate models and identify performance issues.

To the extent PRC-028 standard does not establish an adequate foundation, other standards that rely on operational visibility are also likely to be weakened.

A mismatch between reliability needs and NERC standards will lead to fractured adoption of monitoring across the U.S. as it will require individual ISOs/RTOs and TOs to take independent action. This is already underway, given the lack of existing national standards, common in other countries.

Deferring requirements that mandate the monitoring of IBR performance may contribute to the ongoing trend of IBR performance issues.

Barriers to collecting inverter-level data for existing IBR plants should not prevent the development of inverter-level data requirements for future IBR plants needed for post-event analysis.

The PRC-028 drafting process has demonstrated challenges with retroactively applying inverter-level data requirements. Foregoing development of appropriate 'forward-looking" standards that require inverter-level data for future IBR plants will only exacerbate this problem.

Update the Technical Rationale

The Technical Rationale should include the justification for not including inverter-level requirements as recommended by NERC Reliability Guidelines published in 2018 and 2019.

Continued concern over minimum DDR installation requirements

The SRC notes that in its previous comments, it requested clarification as to whether any or all or none of the DDRs required by PRC-028-1 Requirement R4 are required (or allowed) to be included in the minimum DDR coverage under PRC-002-5 Requirement R5 Part 5.2. The SDT's response indicates that "PRC-002-5 does not apply to IBRs, so the DDR requirements in PRC-028 do not count toward PRC-002. No elements should be covered under both standards as this would set up a double jeopardy situation." The SRC is concerned that as IBR penetration increases, PRC-002-5 Requirement R5 Part 5.2 may put the RC in the position of having to specify additional (and potentially unnecessary) DDR locations simply to satisfy the minimum coverage requirement, despite PRC-028-1 requiring a DDR at each main power transformer of every IBR (meaning that there will likely be enough DDR associated with IBRs to satisfy the minimum coverage requirement within the RC footprint). The SRC recommends that either the coverage requirement be eliminated, or that the coverage calculation be revised to include DDRs associated with IBRs.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The SDT recognizes that SER and FR data from IBR units are helpful in event analysis. The SDT reviewed data requirements from CA-ISO and MISO's tariff and concluded that neither actually requires oscillography data from IBR units. Considering various opposing opinions and to strike a balance between reliability needs, recommendations from various NERC disturbance reports, and cost burden, IBR unit SER data requirement is reintroduced, and SER data from all IBR units is required. However, in lieu of FR data from IBR units, same from collector feeder breakers is specified.

Regarding comment about minimum DDR installations requirements, even with increasing penetration of IBRs, it is very likely that for some operating conditions, system is synchronous machine dominated. For example, Southeast USA region may be solar rich but during cold winter mornings, most load is still expected to be served from synchronous machine-based resources. To ensure adequate coverage considering widely different and various operating conditions, it may not be appropriate to eliminate coverage requirement or revise coverage calculation. However, the SDT does recognize that based on learnings in future, this may be necessary.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. See response to IRC SRC's comment.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comment.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	
Invenergy thanks the drafting team for their work and the opportunity to provide comments. Invenergy has concerns regarding R7.1. and the 20 calendar day data retention requirement for SER, FR, and DDR data. The Technical Rationale for PRC-028-1 states that, "With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable." However, PRC-028-1 will apply to many existing inverter-based resources, some of which have been operational for decades and may possess legacy equipment incapable of storing data for such an extended period of time. Invenergy proposes the below modifications to R7.1.: *7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.*	

7.1.1. If the recording equipment is incapable of storing 20 calendar days of data due to storage constraints, then data shall be retrievable for the maximum allowable period supported by the storage capabilities of the recording equipment, but not less than 10 calendar days.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT realized that in some cases, equipment at some existing IBRs, might need to be replaced to meet requirements of PRC-028. As such, the implementation plan allows appropriate time for existing IBRs. The justification for 20 calendar days retrievability is included in the technical rationale.

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	

Comment

NextEra supports EEI's comments:

EEI offer the following additional Comments:

PRC-028-1 Comments:

Purpose Statement Comments: EEI does not support the addition of Footnote 1 to the Purpose Statement because it inappropriately changes the applicability of PRC-028, outside of the Applicability Section.

Applicability Section Comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.

Requirement R1 Comments:

Subpart 1.1: EEI does not support footnote 2 because it identifies facility scope that is not identified in the Applicability Section and appears to go beyond what was allowed in the approved SAR.

Subpart 1.4: EEI does not support the addition of VSC HVDC equipment because it was not included in the industry approved definition of IBR or this SAR. While EEI is not opposed to including VSC-HVDC equipment to this Reliability Standard if that equipment is in fact creating reliability concerns, no technical justification has been provided to clarify why this is necessary. To address our concern, we ask that that the SAR be revised to include this equipment and submit a technical justification document, as required by the Rules of Procedure (see Standard Processes Manual, Appendix 3a).

Requirement R7 Comments and associated VSLs:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized.

VSL for R7: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

PRC-002-5 Comments:

Applicability Section comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary.

Footnote 2: EEI finds footnote 2 to be confusing and potentially in conflict with the Applicability Section. In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states “For the purposes of this standard, “directly connected” BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1.” We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources (undefined in this standard) are not included. Yet footnote 2 seems to imply BES IBRs connected to a common bus at the same voltage level

within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information. The requirement R7 in PRC-028 is intentionally a bit different from an equivalent requirement R11 in PRC-002. This difference is justified based on differences in "purpose" of both of these standards. Regarding Footnote 2 in PRC-002, the exclusion in 4.2 is applicable to entire standard. In case where a BES IBR is "directly connected" to the identified bus, that BES IBR is excluded from PRC-002 requirements because of exclusion in 4.2. See Figure 1 in PRC-002's technical rationale.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
It is the opinion of ACES that Section 4.2 should be comprehensive and stand-alone; therefore, we disagree with using footnotes to prescribe which inverter-based resources are applicable to this standard. We recommend creating an all-inclusive list as a sub-section of Section 4.2 as shown in our response to question 1. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Richard Vendetti - NextEra Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
NextEra supports EEI's Comments: EEI offer the following additional Comments: PRC-028-1 Comments:	

Purpose Statement Comments: EEI does not support the addition of Footnote 1 to the Purpose Statement because it inappropriately changes the applicability of PRC-028, outside of the Applicability Section.

Applicability Section Comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.

Requirement R1 Comments:

Subpart 1.1: EEI does not support footnote 2 because it identifies facility scope that is not identified in the Applicability Section and appears to go beyond what was allowed in the approved SAR.

Subpart 1.4: EEI does not support the addition of VSC HVDC equipment because it was not included in the industry approved definition of IBR or this SAR. While EEI is not opposed to including VSC-HVDC equipment to this Reliability Standard if that equipment is in fact creating reliability concerns, no technical justification has been provided to clarify why this is necessary. To address our concern, we ask that that the SAR be revised to include this equipment and submit a technical justification document, as required by the Rules of Procedure (see Standard Processes Manual, Appendix 3a).

Requirement R7 Comments and associated VSLs:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized.

VSL for R7: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.

The requirement R7 in PRC-028 is intentionally a bit different from an equivalent requirement R11 in PRC-002. This difference is justified based on differences in "purpose" of both of these standards.

Regarding Footnote 2 in PRC-002, the exclusion in 4.2 is applicable to entire standard. In case where a BES IBR is "directly connected" to the identified bus, that BES IBR is excluded from PRC-002 requirements because of exclusion in 4.2. See Figure 1 in PRC-002's technical rationale.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

PRC-028-1

1. Section B: What is the purpose of removing the need for recording data at the inverter level? It seems like this data is important to record and monitor.

PRC-002-5

1. This document states *"Disturbance monitoring and reporting requirements for inverter-based resources are addressed in PRC-028."*, however, PRC-028-1 draft has removed the requirement for IBR monitoring/reporting.

A general comment: IEEE 2800 does a great job addressing IBRs and could be referenced when making these types of updates for IBRs.

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The inverter level SER data requirement is reintroduced. However, in lieu of inverter level FR data, the FR data from collector feeder breakers is required. This is a compromise considering various opposing views, reliability needs, recommendations from various NERC disturbance reports, and cost burden of implementation PRC-028 standard. During the development, the SDT considered IEEE 2800 requirements, along with comments from various OEMs.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI offer the following additional Comments:

PRC-028-1 Comments:

Purpose Statement Comments: EEI does not support the addition of Footnote 1 to the Purpose Statement because it inappropriately changes the applicability of PRC-028, outside of the Applicability Section.

Applicability Section Comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.

Requirement R1 Comments:

Subpart 1.1: EEI does not support footnote 2 because it identifies facility scope that is not identified in the Applicability Section and appears to go beyond what was allowed in the approved SAR.

Subpart 1.4: EEI does not support the addition of VSC HVDC equipment because it was not included in the industry approved definition of IBR or this SAR. While EEI is not opposed to including VSC-HVDC equipment to this Reliability Standard if that equipment is in fact creating reliability concerns, no technical justification has been provided to clarify why this is necessary. To address our concern, we ask that that the SAR be revised to include this equipment and submit a technical justification document, as required by the Rules of Procedure (see Standard Processes Manual, Appendix 3a).

Requirement R7 Comments and associated VSLs:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors. **Subpart 7.2**: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized. **VSL for R7**: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11. **PRC-002-5 Comments:** **Applicability Section comments:** EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary. **Footnote 2:** EEI finds footnote 2 to be confusing and potentially in conflict with the Applicability Section. In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states "For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1." We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources (undefined in this standard) are not included. Yet footnote 2 seems to imply BES IBRs connected to a common bus at the same voltage level within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information.	

The requirement R7 in PRC-028 is intentionally a bit different from an equivalent requirement R11 in PRC-002. This difference is justified based on differences in "purpose" of both of these standards. Regarding Footnote 2 in PRC-002, the exclusion in 4.2 is applicable to entire standard. In case where a BES IBR is "directly connected" to the identified bus, that BES IBR is excluded from PRC-002 requirements because of exclusion in 4.2. See Figure 1 in PRC-002's technical rationale.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
The standard specific definition for inverter-based resource found in PRC-028 footnote 1 should be placed into item #6 of the **"A. Introduction"** section, as can be seen was done for PRC-005-6 rather than being defined in the footnote. Unless the power level of a collection system feeder breaker is > 75 MVA, the collection system feeder breaker specified in Section 1.2 of the proposed PRC-028 overreaches the BES definition for inverter-based resource. Southern Company does not agree with the language in PRC-028, R8 requiring a Corrective Action Plan to be submitted to the **Regional Entity**. If at any time a Regional Entity desires to review a TO's or GO's Corrective Action Plans, they have the authority to request them. Simply requiring the Corrective Action Plans to be submitted to the Regional Entity with no requirement for the Regional Entity to do something with them is purely administrative and does nothing to improve the reliability of the Bulk Electric System. Further, the timely development and implementation of a Corrective Action Plan needed to repair equipment can be thoroughly examined during an audit engagement. This same reasoning applies to PRC-002, R12 and is also recommended to be removed. Some provision in PRC-028, R7 is needed for an exception to the data delivery requirements for DME equipment that is being repaired as permitted by PRC-028, R8.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The SDT recognizes that collector feeder may not be a BES element. However, the applicability of the standard now included non-BES IBRs given that NERC proposed registration criteria is not approved by FERC. Standard is not limited to monitoring of BES resources or elements only. The proposed compliance extension process is intended to provide a "relief valve" for entities in the event they are unable to comply with the standard's requirements due to circumstances beyond their control. Under this process, entities would explain the circumstances precluding a timely implementation and would receive an extension from the compliance date, and the ERO would maintain its reliability oversight. It is implied that when DME is non-operational as allowed by R8, then data delivery requirements in R7 does not apply.

Scott Thompson - PNM Resources - 1,3 - WECC	
Answer	
Document Name	
Comment	
In addition to EEI's comments, We ask the question, how will new standard be impacted by the new upcoming IBR registration?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The non-BES IBRs are re-introduced in the standard given that new registration criteria is now approved by FERC.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends including a timeframe for implementing the CAPs in both PRC-002-5 Requirement R12 and PRC-028-1 Requirement R8.

In PRC-002-5, Requirement 12 there seems to be an open-ended timeframe for implementing the corrective action plan. Texas RE suggests the following for R12 second bullet:

- Submit a Corrective Action Plan (CAP) and the specific implementation schedule to the Regional Entity within 90 calendar days and implement the CAP according to the timeline specified. The timeline for implementing the CAP shall be within 9 months of the discovery, unless specific reasons for not meeting the timeline is approved by the Regional Entity.

In PRC-028-1, Requirement 8 there seems to be an open-ended timeframe for implementing the corrective action plan. Texas RE suggests the following for R8 second bullet:

- Submit a Corrective Action Plan (CAP) and the specific implementation schedule to the Regional Entity within 90 calendar days and implement the CAP according to the timeline specified. The timeline for implementing the CAP shall be within 9 months of the discovery, unless specific reasons for not meeting the timeline is approved by the Regional Entity.

Synchronous Condensers are dynamic reactive power compensation devices that are becoming essential for stabilizing the grid with the rapid additions of IBRs. Disturbance data from these devices will be valuable when evaluating the BPS disturbances.

Texas RE suggests that the SDT clearly state that the SER data for circuit breakers associated with standalone synchronous condensers and synchronous condensers co-located at the IBR facility(ies) are included in the PRC-028-1 Requirement R1.

Texas RE recommends the following verbiage (in bold):

R1, 1.3 Shunt static or dynamic reactive device(s), **including any filter banks and synchronous condensers.**

Texas RE notes that the redline version does not match the clean version. Please verify that the Draft 3, “redline to last posted” document matches with the draft 3, “clean” version of PRC-028-1 document.

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT recognizes that timeline to implement CAP in PRC-002 - Requirement R11 and PRC-028 - Requirement R7 is open ended. However, failure of recording capability is rare and when occurs would be limited to very few sites on the system. There should be enough coverage of monitoring devices across the system to aid with event analysis during system disturbances. To allow entities some flexibility, it is not necessary to put a strict time line. The entity is required to submit a CAP (including a timeline) to the respective Regional Entity. Including disturbance monitoring requirement for standalone Synchronous Condensers is not in scope of this project. The technical rational includes a statement that synchronous condenser when installed within an IBR is considered a shunt dynamic reactive device. The SDT has reviewed new draft thoroughly, redline and clean versions should match.

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	

Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to other comments.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

The NAGF provides the following additional comments for consideration:

a. General Comments:

i. The NAGF does not agree with requiring that electronic files be provided only in a format that is established by an outside organization. While NAGF acknowledges that C37.111 is the format most used presently, there must still be an option to provide data in a format not controlled by an outside standard as dictated by NERC Rules of Procedure Section 302.6 "Completeness — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance." Therefore, the NAGF recommends that the proposed PRC-002-5 sub-Requirement 11.4 and PRC-028-1 sub-Requirement 7.4 keep the option for providing data in CSV format.

b. PRC-028-1:

i. Requirement 1.1- Please explicitly clarify for offshore wind connected VSC-HVDC plants if the main power transformer includes only the inverter (onshore) transformer or it includes the offshore (rectifier) converter transformer. Note that, for a VSC-HVDC connected offshore wind, the rectifier side reactive power device status will have little impact on the onshore grid and bulk electric system reliability.

ii. Requirement 1.2:

1) the individual feeder buses are not considered BES elements per the NERC BES Definition Reference Document Volume 2, April 2014. It is unclear if the individual feeder-collector bus breakers, which connect to the collector bus, are considered BES. The NAGF requests clarification from the DT on this matter.

2) The NAGF requests clarification for recording of the collector system CB and protection system status for the offshore wind AC system

iii. Requirement 1.3:

1) The NAGF notes that the proposed narrative has the potential to apply to low voltage auxiliary equipment that is not considered BES. Recommend revising the narrative accordingly.

2) Is the synchronous condenser within the IBR plant also considered a part of "dynamic reactive power device(s)"? Note that in most IBR plant designs the synchronous condenser may not provide reactive power compensation; its purpose is to strengthen the grid at the IBR plant POI.

iv. The NAGF requests the DT to consider revising Requirement R1.1 – R1.3 language to clarify the rectifier side data monitoring requirements for VSC-HVDC connected offshore wind facilities.

v. Page 3, footnotes 1 and 2 – recommend moving the footnotes under the Introduction Section – Definitions Used in this Standard (similar to PRC-005-6).

vi. Requirement R7 – Recommend that the narrative be modified to include an exception for missing data that is associated with Corrective Action Plan activities.

vii. Requirement R8 – The NAGF does not see the value of submitting the Corrective Action Plan to the Regional Entity and recommends deleting the associated bullet. This would also apply to PRC-002-5 Requirement R12.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

Relevant requirements are revised and allow for providing data in CSV format.

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	
Thanks for your support.	
Brooke Jockin - Portland General Electric Co. - 1,3,5,6, Group Name Portland General Electric Co.	
Answer	
Document Name	
Comment	

PRC-028: Comments are below:
• R1 Recommend replacing circuit breakers with Interrupting Devices
• R1.2 Recommend replacing collector feeder breakers with collector Interrupting Devices
•
  ○ Each Transmission Owner and Generator Owner shall have sequence of event recording (SER) data for the following Elements circuit breaker position (open/close) sequence of event recording (SER) data for Interrupting Devices that it owns associated with: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* Circuit breaker position (open/close) for circuit breakers associated with the main Main power transformer(s)2.
  ○ cCollector bus(es), including collector Interrupting Devices, and.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. To minimize redlines at this stage in the development process, interrupting device is not introduced in the standard. However, this is reflected in the technical rationale.	
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	
Thanks for your support.	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI's comment.	
Brittany Millard - Lincoln Electric System - 5	
Answer	
Document Name	

Comment	
LES supports MRO NSRF's comment on this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to MRO NSRF's comment.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
Testing and demonstrating performance could be a challenge without further guidance on expectations. · Many existing devices used for fault recording (SEL-351 for example) cannot meet the 2.0 second duration in R3.1.1. A duration of 1.0 second would better align with equipment capabilities. Perhaps the clause could be written that all new equipment should have the 2.0 second duration capability while existing equipment has requirements in-line with the capabilities of the equipment installed over the past few years.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT recognizes that equipment in some existing IBRs may not be able to record data as required by the standard and such equipment needs to be upgraded. The implementation plan allows for an appropriate timeline to just to do that, considering regulatory directive.	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	

Answer	
Document Name	
Comment	

This latest draft of PRC-028-1 continues to diverge further from the IEEE 2800-2022 standard, which is the de facto standard for IBR plants interconnecting with electric transmission systems. This PRC-028-1 standard and other NERC IBR-focused standards should be conforming to/matching the IEEE 2800 standard unless there is excessively strong and clear risk evidence that there is a need to go beyond the requirements in IEEE 2800. Any NERC IBR-focused standard that creates requirements that are less than those in IEEE 2800 is incorrect and faulty.

A lot of the SER/FR/DDR capabilities may not be available in existing IBR plants already connected and operating on the grid. Creating a NERC standard for both existing IBR plants and new/future IBR plants is a difficult task, but creating a standard that is the least common denominator of the capabilities of existing and new facilities would result in a watered-down standard that would not be effective, not be cost effective, and not be valuable in achieving the reliable interconnection and operation of these IBR plants going forward. New IBR plants will most likely be designed to the IEEE 2800 standard going forward, and all these SER/FR/DDR data capture and recording capabilities are therefore all available today and a new NERC standard for these IBRs should be made to utilize these data capabilities for reliable BPS operations. The SER/FR/DDR data sampling rates and data retention rates for IBR units at existing IBR plants would add cost and would require adequate timeframe to implement (as already identified in the draft Implementation Plan for PRC-028-1), but removing these requirements from new/future IBR plants to account for limitations of existing IBR resources seems to go in a negative direction and should have a technically backed justification if it is to remain in the standard as it will set back the industry by significantly underutilizing the full capabilities of new inverters being connected to the grid now and into the future.

Further highlighting the point above, the 2021 Odessa Disturbance report and the NERC IBR Reliability Guideline document both give a recommendation to include SER data for all IBR units (i.e. all inverters) and to include FR/DDR data on some IBR units on the collector busses at IBR plants. These documents point to this Project 2021-04 and recommends including these recommendations as requirements in the updated standard(s).

Related to the 2021 Odessa Disturbance report, in the updated PRC-028-1 Technical Rationale document, page 10 gives reference to the 2021 Odessa Disturbance report. However, in this lasted PRC-028-1 Technical Rational document update there is a redline removal of the report’s recommendation of high-resolution oscillography data for individual IBR units. This redline removal should not have occurred as it removes a key recommendation from the 2021 Odessa report that is specifically important to Project 2021-04 and the new draft PRC-028-1 standard.

This redline removal should be added back into the technical rational document and the IBR unit level SER/FR/DDR requirements should be added back into the draft PRC-028-1 standard.

In continuing the topic of IBR-related NERC Standards not adopting the IEEE 2800-2022 standard, the PRC-002 and the new PRC-028-1 standard both put into place requirements that adopt/require the use of the IEEE C37.111 COMTRADE standard and the IEEE C37.232 COMNAME standard. The language in the PRC-002 and PRC-028 Technical Rational documents highlight that requiring these IEEE industry standards helps the industry with the analysis and other work that is required from these standards. It is exactly that same reason why these updated NERC standards should adopt the IEEE 2800-2022 standard requirements; this would give the industry consistency and clarity on all technical requirements going forward for BPS-connected IBRs. This continued inconsistency regarding NERC's approach and opinion in this area of IEEE 2800 standard adoption should be addressed.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The standard drafting team has considered requirements in IEEE Std 2800 and recommendations from various NERC disturbance reports. The SDT also received input from two OEMs for inverters during the development process. The proposed standard aims to strike a balance between various opinions received from the industry. Considering comments received from the industry, the SER data requirement for IBR units is restored. In lieu of FR data from IBR units, the FR data from collector feeder breakers is required.

Jennifer Bray - Arizona Electric Power Cooperative, Inc. – 1

Answer	
Document Name	

Comment

AEPC signed on to ACES comments:

It is the opinion of ACES that Section 4.2 should be comprehensive and stand-alone; therefore, we disagree with using footnotes to prescribe which inverter-based resources are applicable to this standard. We recommend creating an all-inclusive list as a sub-section of Section 4.2 as shown in our response to question 1.

Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group supports the additional comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NAGF's comments.	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI's comments.	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	
Document Name	
Comment	
We have had no disturbances since the implementation of PRC-002 monitoring. Installation of additional monitoring equipment at all IBR sites will increase capital and operational costs for a very low likelihood event and is not a cost effective approach to protecting the grid. If there are specific regions with a higher risk (history) of disturbance, perhaps the PRC-028 applicability could be amended to include a geographic/regional filter	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The scope of PRC-028 is a bit different from PRC-002. The scope of PRC-028 is to have adequate data available from Inverter-Based Resources to evaluate Inverter-Based Resource ride-through performance during Bulk Electric System (BES) Disturbances and to provide data for Inverter-Based Resource model validation.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Regarding proposed EOP-002-5 R12 changes, the updated language does not address updates to the CAP and its timeline and could lead to a PNC if an entity is unable to meet the target dates originally provided to the Regional Entity.	

Would recommend revising the language to one of the following options for the second bullet under R12: "Submit a Corrective Action Plan (CAP) to the Regional Entity (RE) within 90 calendar days and then implement it in accordance with the most up to date CAP timeline submitted to the RE." OR "Submit a Corrective Action Plan (CAP) to the Regional Entity (RE) within 90 calendar days and then implement it according to CAP timeline or submit an updated CAP to the RE prior to the CAP timeline target."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. It is understood that if the CAP is updated then updated CAP would be submitted to Regional Entity.	
Michael Johnson - Michael Johnson On Behalf of: 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	
Requirement 2.2 “shunt dynamic reactive device data” could be replaced with FACTS. MOD-025/-026 project uses FACTS to refer to these devices and capture Synchronous Condensers, STATCOMS, SVCS, etc. This DT should do the same, so the intent of which devices are intended are the same. Uniformity across standards and standard families is critical for ensuring compliance with the requirements and equipment.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The synchronous condenser is also considered shunt dynamic reactive device. It is recognized that use of synchronous condenser within the IBR plant is rare at this time.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
For R1, include "BES" in R1.2 and R1.3 language. Consideration should be made regarding future overall cost and manufacturer recording equipment availability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Requirement R1 is revised. Inclusion of "BES" is not necessary. Also, note that standard now applies to non-BES IBRs as well. The SDT has always discussed cost implication and need of data for reliability of the grid and requirements are proposed to strike a balance.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
General Comments: (From NAGF) We do not agree with requiring that electronic files be provided only in a format that is established by an outside organization. Although C37.111 is the format most used currently, there must still be an option to provide data in a format not controlled by an outside	

standard as dictated by NERC Rules of Procedure Section 302.6 “Completeness — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.”

PRC-028-1:

i. (From NAGF) Requirement 1.2 - the individual collector buses are not considered BES elements per the NERC BES Definition Reference Document Volume 2, April 2014. Recommend revising the narrative accordingly.

ii. (From NAGF) Requirement 1.3 – the proposed narrative has the potential to apply to low voltage auxiliary equipment that is not considered BES. Recommend revising the narrative accordingly.

iii. (From NAGF) Requirement R7 – Recommend that the narrative be modified to include an exception for missing data that is associated with Corrective Action Plan activities.

iv. (From EEI) Should align Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

v. (From EEI) Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. Requirements should be the same.

vi. (From EEI) VSL for R7: Align the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

vii. (From NAGF) Requirement R8 – Do not see the value of submitting the Corrective

Action Plan to the Regional Entity and recommends deleting the associated bullet.

PRC-002:

(From EEI) Footnote 2: In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states “For the purposes of this standard, “directly connected” BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1.” We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources (undefined in this standard) are not included. Yet footnote 2 seems to imply BES

IBRs connected to a common bus at the same voltage level within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. PRC-002 and 028 now allows sharing of data in CSV format. Requirement R1.2 - The applicability of standard is revised and now applies to non-BES IBRs. Requirement R1.3 – The technical rationale document clearly shows an example of shunt reactive device. The SDT is unaware of a scenario where a dynamic reactive device could be a low voltage auxiliary equipment. Requirement R7 - The R8 clearly states “upon the discovery of a failure of the recording capability”. If the discovery occurs while gathering data under Requirement R7 then it is implied that data won’t be available. The Requirement R7 in PRC-028 deviates a bit from a similar requirement in PRC-002. This is intentional and aligns with scopes of each standard. Requirement R8 – This is similar to an equivalent requirement in PRC-002. PRC-002 excludes all IBRs, regardless of it being “directly connected” to identified bus or not. Technical rationale includes an example to convey this point.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
1. Requirement R7 as drafted seems to imply that in case a failure to record data that is discovered while responding to a data request from an applicable entity, that would constitute a violation of R7. BC Hydro recommends that R7 be revised to clarify that a recording equipment failure would not constitute a compliance violation to R7.	

2. The PRC-028-1 Technical Rationale states on page 13 (Rationale for Requirement R7 section) that, unless an extension is granted, "data has to be provided to the requestor within 20 calendar days after a request". This appears to be in conflict with R7 Part 7.2, which states that "Data subject to Part 7.1 shall be provided within 15 calendar days of a request". Please clarify and revise accordingly. 3. The VSL Table for PRC-028-1 R7 does not seem to set a severity level in case an extension is granted per R7 Part 7.2., e.g. a delay in providing data per the extended deadline does not factor in. Specifically, if an entity were granted an extension to 30 calendar days and provided the required data any number of days past Day 30 could not be assessed a severity level.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The R8 clearly states "upon the discovery of a failure of the recording capability". If the discovery occurs while gathering data under Requirement R7 then it is implied that data won't be available. The technical rationale is revised, second paragraph in Rationale for Requirement R7, and should be consistent with Requirement R7, Part 7.2. The VSL for Requirement R7 is revised and addresses the raised concern.	
Rob Robertson - Leeward Renewable Energy - 5	
Answer	
Document Name	
Comment	
We appreciate some significant improvements in the draft Standard in response to previous comments, particularly removing the requirement for Sequence of Event Recording (SER) and Fault Recording (FR) at individual Inverter-Based Resource (IBR) units, and increasing the plant size threshold for PRC-028 compliance from 20 MVA to Bulk Electric System (BES) resources, which are generally 75 MVA and greater. These improvements, which are noted at the end of our comments, are important and should be retained in the final Standard.	

However, concerns expressed by Leeward Renewables in the most recent comment period, Pine Gate Renewables in the initial comment period, and others have not been fully addressed. These concerns include the cost and burden of 1. Retroactively applying the standard to existing plants and 2. Applying the requirements to smaller plants.{C}[MG1]{C}

We believe the costs and benefits of the proposed standard can be better balanced by 1. Only applying the data collection requirements to plants that sign an interconnection agreement after the effective date of the standard, and 2. Only requiring data collection at IBR generating plants larger than 500 MVA. These changes would greatly reduce the compliance cost and burden while optimizing reliability benefits, as explained below. These changes are also necessary to reduce the disparity between the strict requirements on IBRs in PRC-028 relative to the requirements on synchronous generators in PRC-002, which could result in undue discrimination against IBRs.

1. The Standard’s requirements should only apply prospectively, not retroactively to existing plants

Applying the PRC-028 requirements retroactively to existing generators, as the current draft proposes, greatly exacerbates the cost and burden on generators with minimal benefit. Applying PRC-028 prospectively and not retroactively would avoid the highly costly retrofit of existing facilities, costs that in most cases cannot be recovered by plant owners because existing IBR generators typically sell their output at a fixed price under a long-term power purchase agreement. As noted below, PRC-029 and PRC-030, as well as other modeling and validation Standards revisions that are underway, apply to both existing and new resources. As a result, any concerns about the reliability performance of existing resources will be addressed through those Standards, and thus need not be addressed with PRC-030.

In the initial draft, the requirement to install SER at IBR units in part 1.2 of R1 had an exemption that “IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded,” but that was removed. In the current draft, all requirements apply to all existing and new IBR resources. The retroactive requirement to install SER at IBR units may be particularly challenging in cases in which the OEM that manufactured the inverter is no longer in business, as the records produced by some inverter models are proprietary and require OEM intervention to provide in readable format to the generator owner.

The cost and implementation burden for retrofits is typically much higher than if the data collection equipment were planned and installed as part of initial plant construction. For example, in many cases new data communication wires may have to be run across existing wires, suitable locations must be found to add data collection, storage, and transmission equipment and deliver power to that equipment, and other changes that would be far less costly if they were planned during initial plant design. Adding this equipment also adds ongoing operations and maintenance and compliance costs for that equipment.

Retroactive requirements also impose a much greater financial burden on the generator as those costs cannot typically be recovered once a power purchase agreement has been signed. These unexpected and unrecoverable costs are far more concerning to lenders and other generation project financiers as they were not accounted for during the project's financing. As a result, retroactive requirements set a bad precedent by introducing regulatory uncertainty that makes future generation investment more uncertain and risky, and likely more costly by forcing financiers to charge higher risk premiums.

2. The Standard should only apply to large generators[MG2]

Only applying the requirements to larger IBR plants will greatly reduce the total cost and burden of compliance. The large fixed costs associated with installing and operating the required data collection, storage, and transmission equipment make up a larger share of the total cost of smaller plants. Only applying PRC-028 to larger plants will also make it more comparable to the PRC-002 companion standard for synchronous generators, avoiding undue discrimination against IBRs. As noted below, PRC-029 and PRC-030, as well as other modeling and validation Standards revisions that are underway, would apply to small IBR resources under NERC's IBR registration proposal. As a result, any concerns about the reliability performance of smaller IBR resources will be addressed through those Standards, and thus need not be addressed with PRC-030.

To make the cost of PRC-028 more reasonable while preserving the value of the proposed data collection, as well as avoiding undue discrimination against IBRs relative to synchronous generators, we suggest that data collection in PRC-028 only be required at plants that are 500 MVA and greater. This is the plant size threshold at which synchronous generator dynamic disturbance data collection is required in the PRC-002 standard. If the TO or RC/PC can compellingly demonstrate that smaller new plants should be required to comply with PRC-028's data collection requirements due to local reliability concerns, such as weak grid issues or high penetrations of IBRs in a local area, then that should be allowed. That would avoid an unnecessary cost burden for many smaller plants.

IBR wind, solar, and storage plants are highly modular, so larger IBR plants typically contain the same equipment as smaller plants, just in a larger aggregation (*e.g.,* more collector feeders). Because larger IBR plants are typically just larger aggregations of the equipment in smaller plants, it should be possible to infer the detailed behavior of smaller plants during a disturbance based on the performance of larger plants that are nearby and use similar equipment.

Other Standards and FERC Orders address the reliability concerns addressed by PRC-028, particularly for existing or small IBRs

Regarding potential reliability benefits of the proposed standard, we agree that ride-through issues at some IBRs have presented a legitimate reliability concern. However, the ride-through concerns PRC-028 is primarily attempting to understand have already been addressed by

Federal Energy Regulatory Commission (FERC) Order 2023, the draft PRC-029 and PRC-030 Standards that are currently out for comment and balloting, as well as ongoing Standards revisions to require IBR plant modeling and validation of those models. In particular, reliability concerns about smaller and existing plants are being addressed by these Standards, and thus need not be addressed through PRC-030.

The draft PRC-029 Standard requires all existing and new generators to meet the standard, though existing generators can file for an equipment limitation exemption. Obtaining an exemption requires the owner of the existing generator to document and communicate to the Planning Coordinator "**6.1.2.** Which aspects of voltage ride-through requirements that the IBR would be unable to meet" and "**6.1.3** Identify the specific piece(s) of equipment causing the limitation," so it will be known which existing plants are unable to ride through and why. PRC-030 provides an even more open-ended tool for identifying and addressing unexpected losses of IBR generation, including from both new and existing generators.

In addition, the recent adoption of FERC Order 2023 directly addresses many of the concerns PRC-28 is attempting to address, as it imposes mandatory requirements to fully ride-through grid disturbances and to accurately validate models of plant performance at the sub-second transient timescale. Prior to the adoption of Order 2023 and the development of other NERC Standards, the proposed requirements of PRC-028 may have provided a significant reliability benefit by improving understanding of the ride-through performance of IBRs, and thus helping to identify solutions to any concerns. However, now that FERC Order 2023 and the other NERC Standards have solved many of those concerns by requiring ride-through performance and accurate modeling of sub-second plant performance, it is not clear what reliability benefit PRC-028 might provide.

To the extent the value of PRC-028 was to gather information to help craft improved ride-through requirements through PRC-029, PRC-030, and FERC Order 2023, the window for that opportunity is closing this year, or in the case of FERC Order 2023, has already closed. Data collection equipment installed by the year 2030 pursuant to PRC-028 will not help with designing those standards.

Improvements since the previous draft of PRC-028

As noted above, we appreciate some significant improvements in the draft Standard in response to previous comments. These improvements are important and should be retained in the final Standard:

-Sequence of Event Recording and Fault Recording at individual IBR units is no longer required

-Increasing the plant size threshold for PRC-028 compliance from 20 MVA to BES resources, which are generally 75 MVA and greater

However, concerns about the cost and burden of retroactive application and the application to smaller plants remain, as noted above. Even with the above improvements, the cost and burden of compliance is still significant. The drafting team even noted the burden at pages 125-126 in the Consideration of Comments document for the initial comment period by saying “The Reliability Standard PRC-028-1 is expected to have a wide-ranging impact on Entities as many existing Facilities would be required to have disturbance monitoring equipment. Considering time needed to procure equipment, complete design, schedule outages, and install equipment, technical or supply chain constraints may prevent Entities from being fully compliant in a timeframe stated in the Implementation Plan. Requirement R9 allows Entities of an applicable Facility in commercial operation before the effective date of Reliability Standard PRC-028-1 that is not able to install disturbance monitoring equipment per Requirements R1 through R7 to develop, maintain, and implement a Corrective Action Plan.” There are also significant concerns about the disparity between the strict requirements on IBRs in PRC-028 relative to the requirements on synchronous generators in PRC-002, which could result in undue discrimination against IBRs. For example, R3 in PRC-028 requires IBRs to have FR for 2 seconds (120 cycles) following a disturbance, versus a requirement in PRC-002 for synchronous generators to only record for 30 cycles following a disturbance. IBR behavior is not inherently different enough to justify this difference, and the duration of disturbances faced by IBRs and synchronous generators are identical. There are technical hurdles and cost burdens associated with longer event reports, as they can start to fill up the device working memories and can inadvertently erase older records as those fill up. This is especially challenging when retroactively applying this requirement to sites with legacy data acquisition and storage. Similar concerns are caused by the requirement in PRC-028 R5 for IBRs to have dynamic disturbance recording at a rate of 60 times per second, versus 30 times per second for non-IBRs in PRC-002. As a final example, the synchronization requirement in R6 in PRC-028 is 1 millisecond, versus 2 milliseconds in PRC-002. Given that there are finite resources for complying with all NERC requirements, we are concerned that PRC-028 as proposed could actually undermine reliability by distracting from more pressing reliability needs. We believe the revisions we have proposed to exempt existing and smaller plants and better align the requirements with those imposed on synchronous generators in PRC-002 will result in a Standard that better balances the cost of complying with the Standard with its reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

Considering other comments received, the recording of SER data from IBR units is reintroduced. However, in lieu of IBR unit FR data, FR data from collector feeder breakers is proposed.

FERC recently approved the NERC proposed IBR registration criteria. Given that, the applicability of PRC-028 now includes non-BES IBRs.

The purpose of PRC-028 is to have adequate data available from Inverter-Based Resources to evaluate Inverter-Based Resource ride-through performance during Bulk Electric System (BES) Disturbances and to provide data for Inverter-Based Resource model validation. This is applicable to all IBRs, not just large IBRs or new IBRs. Hence, the standard applies to all IBRs. The implementation plan provides time for installation of disturbance monitoring equipment at existing plants. The data recorded under PRC-028 is to be used to show compliance with PRC-029 (ride-through requirements) and PRC-030 (analysis and mitigation of IBR performance issues).

The differences in requirements for IBRs in PRC-028 compared to PRC-002 are justified based on IBR's fast response during system disturbances, observation of IBR performance over last few years, and recent advancement in monitoring technology. Also note that purpose of these standards is very different.

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of its members regarding PRC-028 Requirement 7:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized.

AZPS requested that 30 days be used for both synchronous generators and IBRS.

VSL for R7: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

AZPS supports the following comments that were submitted by EEI on behalf of their members in regards to PRC-002: **Applicability Section comments:** EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary. **Footnote 2:** EEI finds footnote 2 to be confusing and potentially in conflict with the Applicability Section. In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states "For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1." We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources (undefined in this standard) are not included. Yet footnote 2 seems to imply BES IBRs connected to a common bus at the same voltage level within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information. The requirement R7 in PRC-028 is intentionally a bit different from an equivalent requirement R11 in PRC-002. This difference is justified based on differences in "purpose" of both of these standards. Regarding Footnote 2 in PRC-002, the exclusion in 4.2 is applicable to entire standard. In case where a BES IBR is "directly connected" to the identified bus, that BES IBR is excluded from PRC-002 requirements because of exclusion in 4.2. See Figure 1 in PRC-002's technical rationale.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	

Document Name	
Comment	
Reclamation does not agree with the modifications to the wording of BES Elements in R6 and R7 in the "Violation Severity Levels" section. 'Element' is sufficiently defined in the NERC Glossary of terms and 'BES Element' encompasses the required equipment (elements) for Disturbance Monitoring. Reclamation recommends keeping the original wording "for all applicable BES Elements". Reclamation concurs that all IBR resources should have and maintain their own separate standards.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The change to VSLs in PRC-002 for R6 and R7 is clarifying in nature and does not necessarily change anything compared to previous published version of the standard.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FE supports EEI's comments which offers the following suggestions: PRC-028-1 Comments: Purpose Statement Comments: EEI does not support the addition of Footnote 1 to the Purpose Statement because it inappropriately changes the applicability of PRC-028, outside of the Applicability Section.	

Applicability Section Comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.

Requirement R1 Comments:

Subpart 1.1: EEI does not support footnote 2 because it identifies facility scope that is not identified in the Applicability Section and appears to go beyond what was allowed in the approved SAR.

Subpart 1.4: EEI does not support the addition of VSC HVDC equipment because it was not included in the industry approved definition of IBR or this SAR. While EEI is not opposed to including VSC-HVDC equipment to this Reliability Standard if that equipment is in fact creating reliability concerns, no technical justification has been provided to clarify why this is necessary. To address our concern, we ask that that the SAR be revised to include this equipment and submit a technical justification document, as required by the Rules of Procedure (see Standard Processes Manual, Appendix 3a).

Requirement R7 Comments and associated VSLs:

Subpart 7.1: EEI suggests aligning Requirement R7, Subpart 7.1 with PRC-002, Requirement R11, subpart 11.1. Making the data requirements different in the two standards may cause entities that own both synchronous generators and IBRs to inadvertently make compliance errors.

Subpart 7.2: This requirement seems to parallel Requirement R11, Subpart 11.2 yet the obligation for IBR owners to provide data has been reduced from 30 days to 15 days, while synchronous generator owners are afforded 30 days. EEI does not support this difference and believes these requirements should be harmonized.

VSL for R7: EEI suggests aligning the VSLs for Requirement R7 to what was provided for PRC-002, Requirement R11.

PRC-002-5 Comments:
Applicability Section comments: EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary.
Footnote 2: EEI finds footnote 2 to be confusing and potentially in conflict with the Applicability Section. In the Applicability Section it states that IBRs are excluded from the scope of PRC-002 yet footnote 2 states “For the purposes of this standard, “directly connected” BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1.” We note that certain IBRs are BES Elements, but the Applicability Section stated inverter based resources

(undefined in this standard) are not included. Yet footnote 2 seems to imply BES IBRs connected to a common bus at the same voltage level within the same physical location are to be included in PRC-002. Therefore, if this is the case, then certain IBRs are part of PRC-002. Please clarify what is intended by this footnote or delete it.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The standard is revised and refers to proposed definition of Inverter-Based Resource that is being balloted concurrently with PRC-002/028 ballot. The definition of the Inverter-Based Resource includes plants connected to ac transmission system via VSC-HVDC system. See IBR definition's technical rationale for more information. The requirement R7 in PRC-028 is intentionally a bit different from an equivalent requirement R11 in PRC-002. This difference is justified based on differences in "purpose" of both of these standards. Regarding Footnote 2 in PRC-002, the exclusion in 4.2 is applicable to entire standard. In case where a BES IBR is "directly connected" to the identified bus, that BES IBR is excluded from PRC-002 requirements because of exclusion in 4.2. See Figure 1 in PRC-002's technical rationale.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
Tri-state would like to see Part 7.1 back to the 30 calendar days. 15 days is not enough time.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	

Perhaps this comment is regarding Requirement R7, Part 7.2. The time period of 15 calendar days strikes a compromise or balance between opposing opinions recommending shorter or longer time duration. The entity has a flexibility to request extension when more time is necessary to gather and quality check data before providing to the requester.

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	

For PRC-028-1, R2.2, should it read “Shunt dynamic reactive device FR data” instead of “Shunt dynamic reactive device data”?

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Revised as suggested.

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	
Document Name	
Comment	

TEPC agrees with EEI's comments regarding both PEC-002 and PRC-028:

PRC-002-5 - EEI does not support the Applicability section because it uses the uncapitalized version of IBR. The definition of Inverter Based Resource was approved by the industry during the last posting of that definition and therefore should be capitalized. Additionally, footnote 1 is unnecessary.

PRC-028-1 - EEI does not support the Applicability section because it uses the uncapitalized version of IBR and could unintentionally broaden the scope and create confusion in expectations.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments. The applicability section is revised and refers to proposed definition of Inverter-Based Resource being balloted concurrently with PRC-002/028 ballot.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP applauds the efforts of the standards drafting team for their continued work on this project. We believe that the newest drafts of both standards are greatly improved as compared to their predecessors. AEP is concerned however by recent revisions to PRC-028 R7.2, where all data requested in R7 must be provided within 15 days, rather than the 30 days allowed in the previous draft. In some cases, it will be very difficult to obtain, quality check, and provide this data within a 15-day window. Indeed, extensions might even be necessary in these cases. AEP seeks clarity from the standards drafting team regarding the justification for this, as the current draft of the Technical Rationale document provides no insight. During the webinar on 6/4/2024, the question was asked if a synchronous condenser is to be considered a dynamic reactive device per this standard. AEP would agree with the SDT that a synchronous condenser at an IBR facility should be considered a dynamic reactive device and requiring the desired monitoring. However, AEP would not agree to requiring monitoring "all" synchronous condensers in the transmission system under this SDT effort, and requests this be made clear in the Technical Rationale document. Please note that ERCOT already requires PMU monitoring at new FACTS devices and new synchronous condensers connected to 100kV and above.	

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The time period of 15 calendar days strikes a compromise or balance between opposing opinions recommending shorter or longer time duration. The entity has a flexibility to request extension when more time is necessary to gather and quality check data before providing to the requester.

The PRC-028 applies to Inverter-Based Resources only. The synchronous condensers connected directly to transmission system and not part of Inverter-Based Resources are not in purview of the standard. If the synchronous condenser is installed within the IBR plant to provide dynamic reactive support, then only synchronous condenser to be monitored per requirements applicable to dynamic reactive device.

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	
Document Name	

Comment

Protection relays and most disturbance monitoring equipment does not record power quantities in the FR Comtrade records. The sequence, power, and frequency values can be calculated from the analog values that are recorded in 2.1.1 and 2.1.2. Will it be acceptable to provide a comtrade file with only the individual phase analog values which can be used to calculate the real and reactive power values?

Likes 0	
Dislikes 0	

Response

Thanks for your comment. PRC-002/028 require recorded data to “determine” specified quantities. It is understood that some specified quantities are recorded while others are derived from recorded quantities. For example, active and reactive power is determined based on voltage and current recordings.

Reminder

Standards Announcement

Project 2021-04 Modifications to PRC-002 - Phase II

Additional Ballots and Non-binding Polls Open through June 14, 2024

Now Available

Additional ballots for **Project 2021-04 Modifications to PRC-002 - Phase II** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Friday, June 14, 2024** for the following standards and implementation plan:

- PRC-002-5 – Disturbance Monitoring and Reporting Requirements
- PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- Implementation Plan

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

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.

Note: Votes cast in previous ballots will not carry over to additional ballots. It is the responsibility of the registered voter in the ballot pools to place votes again. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *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 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 2021-04 Modifications to PRC-002 observer list” in the Description Box.

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3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

UPDATED
Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Extended, Now Open through June 17, 2024

Now Available

The formal comment period for **Project 2021-04 Modifications to PRC-002- Phase** II has been extended and is now open through **8 p.m. Eastern, Monday, June 17, 2024** for the following standards and implementation plan:

- PRC-002-5 – Disturbance Monitoring and Reporting Requirements
- PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- Implementation Plan

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact **ballotadmin@nerc.net** to assist with the removal of any duplicate registrations.

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

Additional ballots for the standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels have been extended and will now be conducted **June 5 – 17, 2024**.

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 2021-04 Modifications to PRC-002 observer list" in the Description Box.

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Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Open through June 14, 2024

Now Available

A 15-day formal comment period for **Project 2021-04 Modifications to PRC-002- Phase II** is open through **8 p.m. Eastern, Friday, June 14, 2024** for the following standards and implementation plan:

- PRC-002-5 – Disturbance Monitoring and Reporting Requirements
- PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
- Implementation Plan

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact **ballotadmin@nerc.net** to assist with the removal of any duplicate registrations.

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
Additional ballots for the standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 5 – 14, 2024**.

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 2021-04 Modifications to PRC-002 observer list" 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

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 AB 3 ST
Voting Start Date: 6/5/2024 12:01:00 AM
Voting End Date: 6/17/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 219
Total Ballot Pool: 274
Quorum: 79.93
Quorum Established Date: 6/17/2024 10:07:15 AM
Weighted Segment Value: 77.13

Actions

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	74	1	42	0.808	10	0.192	0	5	17
Segment: 2	8	0.5	4	0.4	1	0.1	0	0	3
Segment: 3	60	1	41	0.82	9	0.18	0	2	8
Segment: 4	14	1	6	0.6	4	0.4	0	2	2
Segment: 5	68	1	36	0.706	15	0.294	0	1	16
Segment: 6	43	1	27	0.794	7	0.206	0	2	7
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	0	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	0	1
Totals:	274	6	161	4.628	46	1.372	0	12	55

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
5	Pattern Operators LP	George E Brown		None	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A

4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	None	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
2	ISO New England, Inc.	John Pearson		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A

1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Affirmative	N/A

1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	AEP	Leshel Hutchings		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
6	AEP	Mathew Miller		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
10	ReliabilityFirst	Lindsey Mannion		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A

3	Sempra - San Diego Gas and Electric	Bryan Bennett	Affirmative	N/A
1	Lakeland Electric	Larry Watt	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas	Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke	Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen	Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden	Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
1	Platte River Power Authority	Marissa Archie	Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos	Affirmative	N/A
6	Constellation	Kimberly Turco	Negative	Comments Submitted
5	Constellation	Alison MacKellar	Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling	Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor	None	N/A
1	Manitoba Hydro	Nazra Gladu	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley	Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins	None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
1	Santee Cooper	Chris Wagner	Abstain	N/A
3	Santee Cooper	Vicky Budreau	Abstain	N/A
5	Santee Cooper	Carey Salisbury	Abstain	N/A
6	Santee Cooper	Marty Watson	Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh	Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman	Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Negative	Comments Submitted

5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A

5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		None	N/A

5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments

2	New York Independent System Operator	Gregory Campoli	None	N/A
4	Utility Services, Inc.	Carver Powers	Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy	None	N/A
2	Independent Electricity System Operator	Helen Lainis	None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz	None	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith	None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 AB 3 ST
Voting Start Date: 6/5/2024 12:01:00 AM
Voting End Date: 6/17/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 214
Total Ballot Pool: 270
Quorum: 79.26
Quorum Established Date: 6/17/2024 11:19:25 AM
Weighted Segment Value: 46.77

Actions

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	72	1	23	0.479	25	0.521	0	7	17
Segment: 2	8	0.5	2	0.2	3	0.3	0	0	3
Segment: 3	59	1	23	0.469	26	0.531	0	2	8
Segment: 4	14	1	3	0.3	7	0.7	0	2	2
Segment: 5	68	1	21	0.42	29	0.58	0	2	16
Segment: 6	42	1	14	0.438	18	0.563	0	2	8
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	0	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	0	1
Totals:	270	6	91	2.806	108	3.194	0	15	56

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		None	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted

1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	None	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
2	ISO New England, Inc.	John Pearson		None	N/A
6	Entergy	Julie Hall		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
					Comments

1	BC Hydro and Power Authority	Adrian Andreoiu	Negative	Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan	Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya	Negative	Third-Party Comments
3	Great River Energy	Michael Brytowski	Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez	None	N/A
1	Great River Energy	Gordon Pietsch	None	N/A
3	WEC Energy Group, Inc.	Christine Kane	Negative	Comments Submitted
1	National Grid USA	Michael Jones	Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar	Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch	Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin	Negative	Comments Submitted
5	National Grid USA	Robin Berry	Negative	Third-Party Comments
3	Ameren - Ameren Services	David Jendras Sr	Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Bill Garvey	Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan	Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy	Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder	Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers	Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer	Negative	Comments Submitted
3	Manitoba Hydro	Mike Smith	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon	Affirmative	N/A

6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
6	AEP	Mathew Miller		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A

1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
10	ReliabilityFirst	Lindsey Mannion		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments

2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Gary Dollins		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A

5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	None	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A

5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
5	Leeward Renewable Energy	Rob Robertson		Negative	Comments Submitted
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A

4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
3	JEA	Marilyn Williams		None	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		None	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II Implementation Plan AB 3 OT
Voting Start Date: 6/5/2024 12:01:00 AM
Voting End Date: 6/17/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 213
Total Ballot Pool: 274
Quorum: 77.74
Quorum Established Date: 6/17/2024 12:36:40 PM
Weighted Segment Value: 62.6

Actions

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	74	1	37	0.74	13	0.26	0	6	18
Segment: 2	7	0.4	1	0.1	3	0.3	0	0	3
Segment: 3	60	1	32	0.653	17	0.347	0	3	8
Segment: 4	14	1	5	0.5	5	0.5	0	2	2
Segment: 5	68	1	28	0.609	18	0.391	0	2	20
Segment: 6	44	1	22	0.667	11	0.333	0	3	8
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	0	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.3	3	0.3	0	0	0	2	1
Totals:	274	5.7	128	3.568	67	2.132	0	18	61

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		None	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted

1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	None	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
5	Northern California Power Agency	Jeremy Lawson		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		None	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A

1	BC Hydro and Power Authority	Adrian Andreoiu	Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan	Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya	Affirmative	N/A
3	Great River Energy	Michael Brytowski	Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez	None	N/A
1	Great River Energy	Gordon Pietsch	None	N/A
3	WEC Energy Group, Inc.	Christine Kane	Negative	Comments Submitted
1	National Grid USA	Michael Jones	Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar	Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz	None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch	Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin	Affirmative	N/A
5	National Grid USA	Robin Berry	Negative	Third-Party Comments
3	Ameren - Ameren Services	David Jendras Sr	Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey	Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup	Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan	Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy	Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder	Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers	Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer	Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon	Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz	Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker	Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle	Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar	Negative	Comments Submitted

1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
6	AEP	Mathew Miller		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A

1	Muscatine Power and Water	Andrew Kurriger		None	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Gary Dollins		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A

1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A

10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments

5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		None	N/A
6	Great River Energy	Brian Meloy		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-002-5 | Non-Binding Poll AB 3 NB
Voting Start Date: 6/5/2024 12:01:00 AM
Voting End Date: 6/17/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 201
Total Ballot Pool: 266
Quorum: 75.56
Quorum Established Date: 6/17/2024 6:34:07 PM
Weighted Segment Value: 79.88

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	35	0.854	6	0.146	11	19
Segment: 2	7	0.3	2	0.2	1	0.1	1	3
Segment: 3	58	1	35	0.833	7	0.167	9	7
Segment: 4	14	1	7	0.7	3	0.3	2	2
Segment: 5	67	1	27	0.711	11	0.289	7	22
Segment: 6	42	1	22	0.815	5	0.185	5	10
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	0

Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	6	0.3	3	0.3	0	0	2	1
Totals:	266	5.6	131	4.412	33	1.188	37	65

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
5	Pattern Operators LP	George E Brown		None	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	None	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
6	Entergy	Julie Hall		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A

3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
6	AEP	Mathew Miller		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		None	N/A
	NiSource - Northern Indiana Public Service				

3	Co.	Steven Taddeucci		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
1	Southern Company - Southern Company	Matt Carden		Affirmative	N/A

	Services, Inc.				
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted

6	Muscatine Power and Water	Nicholas Burns		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
6	Austin Energy	Imane Mrini		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Public Utility District No. 1 of Chelan	Rebecca Zahler		Affirmative	N/A

	County				
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A

1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll AB 3 NB
Voting Start Date: 6/5/2024 12:01:00 AM
Voting End Date: 6/17/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 200
Total Ballot Pool: 261
Quorum: 76.63
Quorum Established Date: 6/17/2024 2:25:19 PM
Weighted Segment Value: 48.15

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	69	1	19	0.514	18	0.486	13	19
Segment: 2	7	0.3	1	0.1	2	0.2	1	3
Segment: 3	57	1	21	0.488	22	0.512	7	7
Segment: 4	14	1	4	0.4	6	0.6	2	2
Segment: 5	66	1	17	0.447	21	0.553	8	20
Segment: 6	41	1	13	0.464	15	0.536	5	8
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	0

Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	6	0.3	3	0.3	0	0	2	1
Totals:	261	5.6	78	2.714	84	2.886	38	61

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		None	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	Oncor Electric Delivery	Byron Booker	Kacie Fischer	None	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted

6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	None	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		None	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted

1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Lakeland Electric	Carmen Rodriguez		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Abstain	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
1	New York Power Authority	Daniel Valle		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A

1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
3	AEP	Leshel Hutchings		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
6	AEP	Mathew Miller		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Lindsey Mannion		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted

1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
1	Platte River Power Authority	Marissa Archie		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
					Comments

5	Evergy	Jeremy Harris	Alan Kloster	Negative	Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	Lakeland Electric	Steven Marshall		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted

5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	None	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
			Chantal		Comments

1	Hydro-Quebec (HQ)	Nicolas Turcotte	Mazza	Negative	Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	JEA	Marilyn Williams		None	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted

3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
2	Independent Electricity System Operator	Helen Lainis		None	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A

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

PRC-028-1 is posted for a formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
25-day formal or informal comment period with additional ballot	March 18, 2024 – April 11, 2024
15-day formal or informal comment period with additional ballot	May 31, 2024 – June 17, 2024
22-day formal or informal comment period with additional ballot	July 22, 2024 – August 12, 2024
10-day final ballot	September 15, 2024 – September 24, 2024
Board adoption	October 15, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be **removed**.

Term(s):

The terms Inverter-Based Resource (IBR) refer to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of Inverter-Based Resource is:

Inverter-Based Resource (IBR): A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

2. **Number:** PRC-028-1

3. **Purpose:** To have adequate data available from Inverter-Based Resources to evaluate Inverter-Based Resource ride-through performance during System Disturbances and to provide data for Inverter-Based Resource model validation.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that owns equipment as identified in section 4.2

   4.2. Facilities:

   4.2.1 BES Inverter-Based Resources

   4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner shall have sequence of event recording (SER) data for the following Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Circuit breaker position (open/close) for circuit breakers associated with the main power transformer(s)[1], collector bus(es), shunt static and dynamic reactive device(s), and AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to Inverter-Based Resource.

1.2. For IBR units[2] in commercial operation after the effective date of this standard, the following data shall be recorded when triggered by ride-through operation or tripping of an IBR unit.

1.2.1. All fault codes.

[1] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for Inverter-Based Resources. In case of dedicated VSC HVDC system connecting to an Inverter-Based Resource, a transformer isolating the DC-AC converter from the transmission system is also considered a main power transformer.

[2] IBR unit includes the inverter, converter, wind turbine generator, or high voltage direct current converter connecting generating resource to alternating current Transmission network.

1.2.2. All fault alarms.

1.2.3. High and low voltage ride-through mode status.

1.2.4. High and low frequency ride-through mode status.

1.3. For IBR units in commercial operation before the effective date of this standard, the following data shall be recorded, if capable, when triggered by ride-through operation or tripping of an IBR unit.

1.3.1. All fault codes.

1.3.2. All fault alarms.

1.3.3. High and low voltage ride-through mode status.

1.3.4. High and low frequency ride-through mode status.

M1. The Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1. Evidence may include, but is not limited to: (1) actual data recordings; or (2) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R2. Each Generator Owner shall have triggered fault recording (FR) data to determine the following electrical quantities for Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. High-side of the main power transformer FR data:

2.1.1. Phase-to-neutral voltage for each phase.

2.1.2. Each phase current and the residual or neutral current.

2.1.3. Real and Reactive Power expressed on a three-phase basis.

2.2. Collector feeder breaker FR data:

2.2.1. Phase-to-neutral voltage for each phase.

2.2.2. Each phase current and the residual or neutral current.

2.2.3. Real and Reactive Power expressed on a three-phase basis.

2.3. Shunt dynamic reactive device FR data:

2.3.1. Phase-to-neutral voltage for each phase.

2.3.2. Each phase current and the residual or neutral current.

2.3.3. Reactive Power output expressed on a three-phase basis.

M2. The Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R2. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R3. Each Generator Owner shall have FR data as specified in Requirement R2 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. High-side of the main power transformer FR data:

3.1.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.1.2. A minimum recording rate of 64 samples per cycle.

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

3.1.3.3. Overfrequency and underfrequency

3.2. Collector feeder breaker FR data:

3.2.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.2.2. A minimum recording rate of 64 samples per cycle.

3.2.3. Trigger settings for at least the following:

3.2.3.1. Neutral (residual) overcurrent, if applicable.

3.2.3.2. AC phase overvoltage and undervoltage.

3.2.3.3. Overfrequency and underfrequency.

3.3. Shunt dynamic reactive device FR data:

3.3.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.3.2. A minimum recording rate of 64 samples per cycle.

3.3.3. Trigger settings for at least the following:

3.3.3.1. Neutral (residual) overcurrent.

3.3.3.2. AC phase overvoltage and undervoltage.

M3. The Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R3. Evidence may include, but is not limited to: (1) actual data recordings or derivations, or (2) documents describing the device specification and device configuration or settings.

R4. Each Generator Owner shall have continuous dynamic disturbance recording (DDR) data and storage to determine the following electrical quantities for each main power transformer(s) it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. One phase-to-neutral or positive sequence voltage on high-side of the main power transformer(s).

4.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R4, Part 4.1, or the positive sequence current.

4.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to each main power transformer(s) where current measurements are required.

4.4. Frequency of any one of the voltage(s) in Requirement R4, Part 4.1.

M4. The Generator Owner has evidence (electronic or hard copy) of continuous DDR data recording and storage to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (3) station drawings.

R5. Each Generator Owner responsible for DDR data for the electrical quantities identified in Requirement R4 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Input sampling rate of at least 960 samples per second.

5.2. Output recording rate of electrical quantities of at least 60 times per second.

M5. The Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R5. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R5, Part 5.1; R5, Part 5.2); or (2) actual data recordings (R5, Part 5.2).

R6. Each Generator Owner shall time synchronize all SER, FR, and DDR data to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

6.2. Synchronized device clock accuracy within ± 1 milliseconds of UTC. The IBR units shall have synchronized device clock accuracy within ± 100 milliseconds of UTC.

M6. The Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R7. Each Generator Owner shall provide all requested SER, FR, and DDR data to its Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within 15 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII[3] Comma Separated Value (CSV) format following Attachment 1.

7.4. FR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

7.5. DDR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

7.6. Data files shall be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M7. The Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R7. Evidence may include, but is not limited to: (1) actual data recordings; (2) dated transmittals to the requesting entity with formatted records; or (3) documents describing data storage capability, device specification, configuration, or settings.

R8. Each Generator Owner shall, upon the discovery of a failure of the recording capability for the SER, FR, or DDR data: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

M8. The Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R8. Evidence may include, but is not limited to: (1) dated reports of the discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated Corrective Action Plan transmittals to the Regional Entity and evidence of Corrective Action Plan implementation.

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[3] American Standard Code for Information Exchange

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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

   The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

   The Generator Owner shall retain evidence, as per Requirements R1 through R8, for three calendar years.

   If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

   The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

   1.3. **Compliance Monitoring and Enforcement Program:** 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 associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the circuit breaker(s) identified in Requirement R1.
R2	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.
R3	The Generator Owner had FR data that meets more	The Generator Owner had FR data that meets more	The Generator Owner had FR data that meets more	The Generator Owner had FR data that meets less

	than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	than or equal to 60 percent of the total recording parameters as specified in Requirement R3.
R4	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.
R5	The Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

R6	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.
R7	The Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data one to 10 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 90 percent of the data, but less than 100 percent of	The Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data 11 to 20 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 80 percent of the data, but less than or equal to 90 percent	The Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data 21 to 30 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 70 percent of the data, but less than or equal to 80	The Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 30 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided less than or equal to 70 percent of the data in the proper data format.

	the data in the proper data format.	of the data in the proper data format.	percent of the data in the proper data format.	
R8	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-028-1: Implementation Plan.

NERC Reliability Standard PRC-028-1: Technical Rationale.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011: IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

IEEE Std 2800-2022: IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.

Multiple Solar PV Disturbances in CAISO, Joint NERC and WECC Staff Report, April 2022.

NERC Reliability Standard PRC-002-5.

Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021, Joint NERC and Texas RE Event Report, September 2021.

Odessa Disturbance, Texas Event: June 4, 2022, Joint NERC and Texas RE Event Report, December 2022.

Version History

Version	Date	Action	Change Tracking
0	TBD	Developed by Project 2021-04 Drafting Team	New

Attachment 1

Sequence of Events Recording (SER) Data Format

(Requirement R7, Part 7.3)

Date, Time, Local Time Code, Plant Name, Device[4], State[5]

08/27/23, 23:58:57.110, -5, Plant name 1, Breaker 1, Close

08/27/23, 23:58:57.082, -5, Plant name 2, Breaker 2, Close

08/27/23, 23:58:57.217, -5, Plant name 1, IBR unit 1, undervoltage ride-through mode

08/27/23, 23:58:57.214, -5, Plant name 2, IBR unit 2, dc overcurrent trip

[4] Device name may include specific names of breakers or IBR units as appropriate.

[5] Breaker status and any other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is acceptable. For IBR unit level data, fault codes, alarms, change in operating mode etc., are also acceptable.

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

PRC-028-1 is posted for a formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
25-day formal or informal comment period with additional ballot	March 18, 2024 – April 11, 2024
15-day formal or informal comment period with additional ballot	May 31, 2024 – June 17, 2024
22-day formal or informal comment period with additional ballot	July 22, 2024 – August 12, 2024
10-day final ballot	September 15, 2024 – September 24, 2024
Board adoption	October 15, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be **removed**.

Term(s):

The terms Inverter-Based Resource (IBR) refer to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of Inverter-Based Resource is:

~~N/A~~ **Inverter-Based Resource (IBR):** A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

2. **Number:** PRC-028-1

3. **Purpose:** To have adequate data available from ~~i~~Inverter-~~b~~Based ~~r~~Resources~~[1]~~ to evaluate ~~i~~Inverter-~~b~~Based ~~r~~Resource ride-through performance during ~~Bulk Electric~~ System ~~(BES)~~ Disturbances and to provide data for ~~i~~Inverter-~~b~~Based ~~r~~Resource model validation.

4. **Applicability:**

   4.1. Functional Entities:

   ~~4.1.1. Transmission Owner that owns equipment as identified in section 4.2~~

   ~~4.1.2.~~4.1.1. Generator Owner that owns equipment as identified in section 4.2

   4.2. Facilities:

   4.2.1 BES ~~i~~Inverter-~~b~~Based ~~r~~Resources

   ~~4.1.1~~4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each ~~Transmission Owner and~~ Generator Owner shall have ~~circuit breaker position (open/close)~~ sequence of event recording (SER) data for the following Elements~~circuit breakers~~ that it owns~~associated with~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~1.1.~~ Circuit breaker position (open/close) for circuit breakers associated with the ~~Main~~ main power transformer(s)[2], collector bus(es), shunt static and dynamic reactive device(s), and AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to Inverter-Based Resource.

~~[1] For the purpose of this standard, "inverter-based resources" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource includes VSC HVDC line.~~

[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for ~~i~~Inverter-~~b~~Based ~~r~~Resources. In case of dedicated VSC HVDC system connecting to an ~~i~~Inverter-~~b~~Based ~~r~~Resource, a transformer isolating the DC-AC converter from the transmission system is also considered a main power transformer.

~~**1.2.** Collector bus(es), including collector feeder breakers.~~

~~**1.3.** Shunt static or dynamic reactive device(s).~~

1.1. ~~AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to inverter-based resource.~~

1.2. For IBR units[3] in commercial operation after the effective date of this standard, the following data shall be recorded when triggered by ride-through operation or tripping of an IBR unit.

1.2.1. All fault codes.

1.2.2. All fault alarms.

1.2.3. High and low voltage ride-through mode status.

1.2.4. High and low frequency ride-through mode status.

1.3. For IBR units in commercial operation before the effective date of this standard, the following data shall be recorded, if capable, when triggered by ride-through operation or tripping of an IBR unit.

1.3.1. All fault codes.

1.3.2. All fault alarms.

1.3.3. High and low voltage ride-through mode status.

~~**1.3.1.**~~**1.3.4.** High and low frequency ride-through mode status.

M1. The ~~Transmission Owner or~~ Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1. Evidence may include, but is not limited to: (1) actual data recordings; or (2) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R2. Each ~~Transmission Owner and~~ Generator Owner shall have triggered fault recording (FR) data to determine the following electrical quantities for Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. High-side of the main power transformer FR data:

2.1.1. Phase-to-neutral voltage for each phase.

2.1.2. Each phase current and the residual or neutral current.

2.1.3. Real and R~~r~~eactive ~~p~~Power expressed on a three-phase basis.

2.2. Collector feeder breaker FR data:

2.2.1. Phase-to-neutral voltage for each phase.

[3] IBR unit includes the inverter, converter, wind turbine generator, or high voltage direct current converter connecting generating resource to alternating current Transmission network.

2.2.2. Each phase current and the residual or neutral current.

~~2.1.3.~~2.2.3. Real and Reactive Power expressed on a three-phase basis.

~~2.2.~~2.3. Shunt dynamic reactive device FR data:

~~2.2.1.~~2.3.1. Phase-to-neutral voltage for each phase.

~~2.2.2.~~2.3.2. Each phase current and the residual or neutral current.

~~2.2.3.~~2.3.3. Reactive P~~p~~ower output expressed on a three-phase basis.

M2. The ~~Transmission Owner or~~ Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R2. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R3. Each ~~Transmission Owner and~~ Generator Owner shall have FR data as specified in Requirement R2 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. High-side of the main power transformer FR data:

3.1.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.1.2. A minimum recording rate of 64 samples per cycle.

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

~~3.1.3.2.~~3.1.3.3. Overfrequency and underfrequency

3.2. Collector feeder breaker FR data:

3.2.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

3.2.2. A minimum recording rate of 64 samples per cycle.

3.2.3. Trigger settings for at least the following:

3.2.3.1. Neutral (residual) overcurrent, if applicable.

3.2.3.2. AC phase overvoltage and undervoltage.

3.2.3.3. Overfrequency and underfrequency.

~~3.2.~~3.3. Shunt dynamic reactive device FR data:

~~3.2.1.~~3.3.1. A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 2.0 seconds for the same trigger point.

~~3.2.2.~~3.3.2. A minimum recording rate of 64 samples per cycle.

~~3.2.3.~~3.3.3. Trigger settings for at least the following:

~~3.2.3.1.~~3.3.3.1. Neutral (residual) overcurrent.

~~3.2.3.2.~~3.3.3.2. AC phase overvoltage and undervoltage.

M3. The ~~Transmission Owner or~~ Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R3. Evidence may include, but is not limited to: (1) actual data recordings or derivations, or (2) documents describing the device specification and device configuration or settings.

R4. Each Generator Owner ~~and Transmission Owner~~ shall have continuous dynamic disturbance recording (DDR) data and storage to determine the following electrical quantities for each main power transformer(s) it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. One phase-to-neutral or positive sequence voltage on high-side of the main power transformer(s).

4.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R4, Part 4.1, or the positive sequence current.

4.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to each main power transformer(s) where current measurements are required.

4.4. Frequency of any one of the voltage(s) in Requirement R4, Part 4.1.

M4. The Generator Owner ~~or Transmission Owner~~ has evidence (electronic or hard copy) of continuous DDR data recording and storage to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (3) station drawings.

R5. Each ~~Transmission Owner and~~ Generator Owner responsible for DDR data for the electrical quantities identified in Requirement R4 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Input sampling rate of at least 960 samples per second.

5.2. Output recording rate of electrical quantities of at least 60 times per second.

M5. The ~~Transmission Owner or~~ Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R5. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R5, Part 5.1; R5, Part 5.2); or (2) actual data recordings (R5, Part 5.2).

R6. Each ~~Transmission Owner and~~ Generator Owner shall time synchronize all SER, FR, and DDR data to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

6.2. Synchronized device clock accuracy within ± 1 milliseconds of UTC. The IBR units shall have synchronized device clock accuracy within ± 100 milliseconds of UTC.

M6. The ~~Transmission Owner or~~ Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R7. Each ~~Transmission Owner and~~ Generator Owner shall provide all requested SER, FR, and DDR data to its Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within 15 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII[4] Comma Separated Value (CSV) format following Attachment 1.

7.4. FR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

7.5. DDR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted in conformance with C37.111, IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

7.6. Data files shall be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M7. The ~~Transmission Owner or~~ Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R7. Evidence may include, but is not limited to: (1) actual data recordings; (2) dated transmittals to

[4] American Standard Code for Information Exchange

the requesting entity with formatted records; or (3) documents describing data storage capability, device specification, configuration, or settings.

R8. Each ~~Transmission Owner and~~ Generator Owner shall, upon the discovery of a failure of the recording capability for the SER, FR, or DDR data: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

M8. The ~~Transmission Owner or~~ Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R8. Evidence may include, but is not limited to: (1) dated reports of the discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated Corrective Action Plan transmittals to the Regional Entity and evidence of Corrective Action Plan implementation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: “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 periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The ~~Transmission Owner and~~ Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The ~~Transmission Owner and~~ Generator Owner shall retain evidence, as per Requirements R1 through R8, for three calendar years.

If a ~~Transmission Owner or~~ Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records, and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: 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 associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Each ~~Transmission Owner or~~ Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the circuit breaker(s) identified in Requirement R1.	Each ~~Transmission Owner or~~ Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the circuit breaker(s) identified in Requirement R1.	Each ~~Transmission Owner or~~ Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the circuit breaker(s) identified in Requirement R1.	Each ~~Transmission Owner or~~ Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the circuit breaker(s) identified in Requirement R1.
R2	The ~~Transmission Owner or~~ Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The ~~Transmission Owner or~~ Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The ~~Transmission Owner or~~ Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The ~~Transmission Owner or~~ Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

R3	The ~~Transmission Owner or~~ Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The ~~Transmission Owner or~~ Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The ~~Transmission Owner or~~ Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The ~~Transmission Owner or~~ Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.
R4	The ~~Transmission Owner or~~ Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The ~~Transmission Owner or~~ Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The ~~Transmission Owner or~~ Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The ~~Transmission Owner or~~ Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.
R5	The ~~Transmission Owner or~~ Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the	The ~~Transmission Owner or~~ Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the	The ~~Transmission Owner or~~ Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70	The ~~Transmission Owner or~~ Generator Owner had DDR data that meets less than or equal to 60 percent of the total

	total recording parameters as specified in Requirement R5.	total recording properties as specified in Requirement R5.	percent of the total recording properties as specified in Requirement R5.	recording properties as specified in Requirement R5.
R6	The ~~Transmission Owner or~~ Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The ~~Transmission Owner or~~ Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The ~~Transmission Owner or~~ Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The ~~Transmission Owner or~~ Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.
R7	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data one to 10 calendar days late~~more than 15 calendar days, but less than or equal to 25~~	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data 11 to 20 ~~more than 25~~ calendar days late~~, but less than or equal to 35 calendar days after~~	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data 21 to 30 calendar days late~~more than 35 calendar days, but less than or equal to 45~~	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 30~~45~~ calendar days late~~after the request,~~

	~~calendar days after the request, unless an extension was granted by the requestor~~. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	~~the request, unless an extension was granted by the requestor~~. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	~~calendar days after the request, unless an extension was granted by the requestor~~. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	~~unless an extension was granted by the requestor~~. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided less than or equal to 70 percent of the data in the proper data format.
R8	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR ~~Transmission Owner or~~ Generator Owner as directed by Requirement

			The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-028-1: Implementation Plan.

NERC Reliability Standard PRC-028-1: Technical Rationale.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

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Implementation Plan

Project 2021-04
Reliability Standards PRC-002-5 and PRC-028-1

Applicable Standard(s)

- PRC-002-5 Disturbance Monitoring and Reporting Requirements
- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

Requested Retirement(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner (TO)
- Generator Owner (GO)

General Considerations

Additional time to implement Reliability Standard PRC-002-5 is not provided because the revisions are clarifying in nature to exclude Inverter-Based Resources (or "IBRs) from PRC-002 applicability as they are included in PRC-028. The revision to PRC-002 does not require any additional procurement or installation of Disturbance Monitoring Equipment.

Reliability Standard PRC-028-1 is expected to have wide ranging impact on GOs, as many existing and new facilities would be required to have Disturbance Monitoring Equipment. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities. The implementation plan takes into account scheduling outages needed to implement sequence of events recording, fault recording, and dynamic disturbance recording capability. The implementation plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities.

The ERO enterprise acknowledges that Generator Owners and Generator Operators owning or operating Bulk-Power System connected IBRs that do not meet NERC's current definition of Bulk Electric System ("BES") will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, this implementation plan provides additional time for both new and existing registered entities to come into compliance with Reliability Standard PRC-028-1 for their applicable Inverter-Based Resources not meeting BES definition. In so doing, this implementation plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the Bulk-Power System.

The implementation plan recognizes the Federal Energy Regulatory Commission's directive to have this standard effective and enforceable before 2030.[1]

Effective Date of PRC-002-5

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-002-5 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-002-5 shall become effective 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.

Effective Date of PRC-028-1 and Phased-in Compliance Dates

The effective date for proposed Reliability Standard PRC-028-1 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard PRC-028-1

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

BES Inverter-Based Resources

Compliance Date for PRC-028-1 Requirements R1-R7

[1] See Order No. 901 at P226.

For BES Inverter-Based Resources in commercial operation on or before the effective date: Entities shall comply with Requirements R1 through R7 at 50% of their BES Inverter-Based Resources within three (3) calendar years of the effective date of PRC-028-1 and 100% of their BES Inverter-Based Resources by January 1, 2030.

Entities that are required to monitor only one (1) BES Inverter-Based Resource shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of Reliability Standard PRC-028-1.

For BES Inverter-Based Resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later. As an example: Assume the effective date of the PRC-028-1 is July 1, 2025:

- For BES IBRs entering commercial operation after July 1, 2025, but on or before October 1, 2026, entities shall comply with Requirements R1 through R7 by October 1, 2026.
- For BES IBRs entering commercial operation after October 1, 2026, entities shall comply with Requirements R1 through R7 on the commercial operation date.

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than nine (9) months after the effective date of Reliability Standard PRC-028-1.

Non-BES Inverter-Based Resources

The “Non-BES Inverter-Based Resources” are those that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Compliance Date for PRC-028-1 Requirements R1-R7

For non-BES Inverter-Based Resources in commercial operation on or before May 2026: Entities shall comply with Requirements R1 through R7 at 100% of their non-BES Inverter-Based Resources by January 1, 2030.

For non-BES Inverter-Based Resources in commercial operation after May 2026: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later.

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than April 1, 2027.

Process for Requesting an Extension from Compliance Dates

Each GO that owns one or more applicable Inverter-Based Resources that are in commercial operation before the effective date of Reliability Standard PRC-028-1 may request an extension from the above-listed compliance dates if circumstances beyond its control prevent the installation of Disturbance Monitoring Equipment on one or more of its Inverter-Based Resources.

To request an extension, the entity shall develop and submit to its Compliance Enforcement Authority[2] a request for extension that contains at a minimum the following information:

1.1. Identification of the Inverter-Based Resource(s) for which the entity requests the extension;

1.2. A plan for installing the Disturbance Monitoring Equipment and a timetable for completion;

1.3. A description of the circumstances precluding the timely installation of Disturbance Monitoring Equipment and how those circumstances are beyond the control of the entity; and

1.4. Any other information the entity deems relevant to the Compliance Enforcement Authority's consideration of its request.

Circumstances beyond the entity's control may include supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside the entity's control.

The entity shall provide any information requested by the Compliance Enforcement Authority to validate the information provided above, including any information specified by the Compliance Enforcement Authority in a supporting process document. If the extension request is granted, the entity shall implement the plan in accordance with the provided timetable. Should additional time be required, the entity shall submit an updated request to its Compliance Enforcement Authority.

Requests should be submitted as soon as the entity identifies circumstances impeding the timely implementation of Reliability Standard PRC-028-1, but no later than three months prior to the compliance date for which the entity requests an extension.

[2] The extension requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

Retirement Date

Reliability Standard PRC-002-4 shall be retired immediately prior to the effective date of Reliability Standard PRC-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Project 2021-04
Reliability Standards PRC-002-5 and PRC-028-1

Applicable Standard(s)

- PRC-002-5 Disturbance Monitoring and Reporting Requirements
- PRC-028-1 Disturbance Monitoring and Reporting Requirements for ~~i~~Inverter-~~b~~Based ~~r~~Resources

Requested Retirement(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner (TO)
- Generator Owner (GO)

General Considerations

Additional time to implement Reliability Standard PRC-002-5 is not provided because the revisions are clarifying in nature to exclude ~~i~~Inverter-~~b~~Based ~~r~~Resources (or "IBRs) from PRC-002 applicability as they are included in PRC-028. The revision to PRC-002 does not require any additional procurement or installation of Disturbance Monitoring Equipment.

~~The~~ Reliability Standard PRC-028-1 is expected to have wide ranging impact on ~~TOs and~~ GOs, as many existing and new facilities would be required to have Disturbance Monitoring Equipment. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities. The ~~I~~implementation ~~P~~plan takes into account scheduling outages needed to implement sequence of events recording, fault recording, and dynamic disturbance recording capability. ~~An entity owning only one (1) identified inverter-based resource is allowed three (3) calendar years for implementation to accommodate normal outage schedules.~~ The ~~I~~implementation ~~P~~plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities.

The ERO enterprise acknowledges that Generator Owners and Generator~~s~~ Operators owning or operating Bulk-Power System connected IBRs that do not meet NERC's current definition of Bulk Electric System ("BES") will be registered no later than May 2026 in accordance with the IBR Registration proceeding in FERC Docket No. RR24-2. To ensure an orderly registration and compliance process for these entities, as well as fairness and consistency in the standard's application among similar asset types, this implementation plan provides additional time for both new and existing registered entities to come into compliance with Reliability Standard PRC-028-1 for their applicable Inverter-Based Resources not meeting BES definition. In so doing, this implementation plan advances an orderly process for new registrants while allowing existing entities to focus their immediate efforts on their assets posing the highest risk to the reliable operation of the Bulk-Power System.

The ~~I~~implementation ~~P~~plan recognizes the Federal Energy Regulatory Commission's directive to have this standard effective and enforceable before 2030.[1]

Effective Date of PRC-002-5

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-002-5 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-002-5 shall become effective 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.

Effective Date of PRC-028-1 and Phased-in Compliance Dates

The effective date for proposed Reliability Standard PRC-028-1 is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard PRC-028-1

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard PRC-028-1 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

[1] See Order No. 901 at P226.

BES Inverter-Based Resources

Compliance Date for PRC-028-1 Requirements R1-R7

For BES ~~i~~Inverter-~~b~~Based ~~r~~Resources in commercial operation on or before the effective date:
Entities shall comply with Requirements R1 through R7 at 50% of their BES ~~i~~Inverter-~~b~~Based ~~r~~Resources within three (3) calendar years of the effective date of PRC-028-1 and 100% of their BES ~~i~~Inverter-~~b~~Based ~~r~~Resources by January 1, 2030.

Entities that are required to monitor only one (1) BES ~~i~~Inverter-~~b~~Based ~~r~~Resource shall comply with Requirements R1 through R7 within three (3) calendar years of the effective date of Reliability Standard PRC-028-1.

For BES ~~i~~Inverter-~~b~~Based ~~r~~Resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later. As an example: Assume the effective date of the PRC-028-1 is July 1, 2025:

- For BES IBRs entering commercial operation after July 1, 2025, but on or before October 1, 2026, entities shall comply with Requirements R1 through R7 by October 1, 2026.
- For BES IBRs entering commercial operation after October 1, 2026, entities shall comply with Requirements R1 through R7 on the commercial operation date.

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than nine (9) months after the effective date of Reliability Standard PRC-028-1.

Non-BES Inverter-Based Resources

The "Non-BES Inverter-Based Resources" are those that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Compliance Date for PRC-028-1 Requirements R1-R7

For non-BES Inverter-Based Resources in commercial operation on or before May 2026:
Entities shall comply with Requirements R1 through R7 at 100% of their non-BES Inverter-Based Resources by January 1, 2030.

For non-BES Inverter-Based Resources in commercial operation after May 2026:
Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later.

Compliance Date for PRC-028-1 Requirement R8

Entities shall comply with Requirement R8 by no later than April 1, 2027.

Process for Requesting~~Seeking~~ an Extension from Compliance Dates

Each GO ~~and TO~~ that owns one or more applicable ~~i~~Inverter-~~b~~Based ~~r~~Resources that are in commercial operation before the effective date of Reliability Standard PRC-028-1 may ~~seek~~request an extension from the above-listed compliance dates if circumstances beyond its control prevent the installation of Disturbance Monitoring Equipment on one or more of its ~~i~~Inverter-~~b~~Based ~~r~~Resources.

To request~~seek~~ an extension, the entity shall develop and submit to its ~~Regional Entity~~Compliance Enforcement Authority[2]~~[3]~~ a request for extension that contains at a minimum the following information:

1.1. Identification of the ~~i~~Inverter-~~b~~Based ~~r~~Resource(s) for which the entity requests~~seeks~~ the extension;

1.2. A plan for installing the Disturbance Monitoring Equipment and a timetable for completion;

1.3. A description of the circumstances precluding the timely installation of Disturbance Monitoring Equipment and how those circumstances are beyond the control of the entity; and

1.4. Any other information the entity deems relevant to the Compliance Enforcement Authority~~Regional Entity~~'s consideration of its request.

Circumstances beyond the entity's control may include supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside the entity's control.

The entity shall provide any information requested by the ~~Regional Entity~~ Compliance Enforcement Authority to validate the information provided above~~in connection with its request~~, including any information specified by the Compliance Enforcement Authority in a supporting process document. If the extension request is granted, the entity shall implement the plan in accordance with the

[2] The extension requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
~~[3] This is the Regional Entity that will receive any Corrective Action Plans developed in accordance with Requirement R8.~~

provided timetable. Should additional time be required, the entity shall submit an updated request to its Compliance Enforcement Authority~~Regional Entity~~.

Requests should be submitted as soon as the entity identifies circumstances impeding~~prescribing~~ the timely implementation of Reliability Standard PRC-028-1, but no later than three months prior to the compliance date for which the entity ~~seek~~requests an extension.

Retirement Date

Reliability Standard PRC-002-4 shall be retired immediately prior to the effective date of Reliability Standard PRC-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2021-04 Modifications to PRC-002 – Phase II

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources** by **8 p.m. Eastern, Monday, August 12, 2024.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 470-542-6882.

Background Information

This project will be completed in two phases. The first phase addressed the scope regarding notifications relative to the sequence of events recording (SER) and fault recording (FR) data, and to clearly identify the BES Element owners that need to have SER and FR data for transformers and transmission lines with the associated identified bus in the Glencoe Light and Power Standard Authorization Request.

The second phase will address gaps the Inverter-based Resource Performance Task Force identified within the PRC-002. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System that may not be covered by the existing requirements.

Questions

1. Do you agree with the modification made in PRC-028-1?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the Implementation Plan for revised PRC-028-1?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree the modifications made in PRC-028-1 are cost effective at unit level cost versus plant level cost compared to the benefit to reliability?

   ☐ Yes
   ☐ No

   Comments:

4. Provide any additional comments for the standard drafting team to consider, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II
(PRC-028-1)

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 PRC-028-1. 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-028-1

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the circuit breaker(s) identified in Requirement R1.

VSL Justifications for PRC-028-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R1	
Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 80 percent, but less than 100	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 70 percent, but less than or	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than 60 percent, but less than or	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers less than or equal to 60 percent of the

percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-028-1, Requirement R2	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R3	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
	capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R4	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
Guideline 2- Consistency within a Reliability Standard	and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

VSL Justifications for PRC-028-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 15 calendar days, but less than or equal to 25 calendar days after the request, unless an	The Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 25 calendar days, but less than or equal to 35 calendar days after the request, unless an	The Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 35 calendar days, but less than or equal to 45 calendar days after the request, unless an	The Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 45 calendar days after the request, unless an extension was granted by the requestor.

extension was granted by the requestor. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	extension was granted by the requestor. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	extension was granted by the requestor. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The Generator Owner as directed by Requirement R8 submitted a	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and failed to provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR The Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90

		Corrective Action Plan to the Regional Entity but failed to implement it.	calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-028-1, Requirement R8	
Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002 – Phase II (PRC-028-1)

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 PRC-028-1. 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-028-1

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.

VRF Justifications for PRC-028-1, Requirement R1	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
Each ~~Transmission Owner or~~ Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the circuit breaker(s) identified in Requirement R1.	Each ~~Transmission Owner or~~ Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the circuit breaker(s) identified in Requirement R1.	Each ~~Transmission Owner or~~ Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the circuit breaker(s) identified in Requirement R1.	Each ~~Transmission Owner or~~ Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the circuit breaker(s) identified in Requirement R1.

VSL Justifications for PRC-028-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R1	
Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.

VRF Justifications for PRC-028-1, Requirement R2	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The ~~Transmission Owner or~~ Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than	The ~~Transmission Owner or~~ Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than	The ~~Transmission Owner or~~ Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers more than	The ~~Transmission Owner or~~ Generator Owner had FR data as directed by Requirement R2, Parts 2.1 and 2.2 that covers less than or

80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-028-1, Requirement R2	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.

VRF Justifications for PRC-028-1, Requirement R3	
Proposed VRF	**Lower**
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The ~~Transmission Owner or~~ Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	The ~~Transmission Owner or~~ Generator Owner had FR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	The ~~Transmission Owner or~~ Generator Owner had FR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	The ~~Transmission Owner or~~ Generator Owner had FR data that meets less than or equal to 60 percent of the total recording parameters as specified in Requirement R3.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-028-1, Requirement R3	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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

VRF Justifications for PRC-028-1, Requirement R4	
Proposed VRF	**Lower**
	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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The ~~Transmission Owner or~~ Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The ~~Transmission Owner or~~ Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The ~~Transmission Owner or~~ Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The ~~Transmission Owner or~~ Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.

VSL Justifications for PRC-028-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R4	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments

VRF Justifications for PRC-028-1, Requirement R5	
Proposed VRF	**Lower**
Guideline 2- Consistency within a Reliability Standard	and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The ~~Transmission Owner or~~ Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The ~~Transmission Owner or~~ Generator Owner had DDR data that meets more than 70 percent, but less than or equal to 80 percent of the total recording properties as specified in Requirement R5.	The ~~Transmission Owner or~~ Generator Owner had DDR data that meets more than 60 percent, but less than or equal to 70 percent of the total recording properties as specified in Requirement R5.	The ~~Transmission Owner or~~ Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

VSL Justifications for PRC-028-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The ~~Transmission Owner or~~ Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The ~~Transmission Owner or~~ Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The ~~Transmission Owner or~~ Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The ~~Transmission Owner or~~ Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R7	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 15 calendar days, but less than or equal to 25 calendar days after the	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 25 calendar days, but less than or	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 35 calendar days, but less than or	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 45 calendar days after the request,

request, unless an extension was granted by the requestor. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	equal to 35 calendar days after the request, unless an extension was granted by the requestor. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	equal to 45 calendar days after the request, unless an extension was granted by the requestor. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	unless an extension was granted by the requestor. OR The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided less than or equal to 70 percent of the data in the proper data format.

VSL Justifications for PRC-028-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-028-1, Requirement R7	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R1 is consistent with those connections between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

VRF Justifications for PRC-028-1, Requirement R8	
Proposed VRF	**Lower**
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-028-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days, but less than or equal to 100 calendar days after discovery of the failure.	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days, but less than or equal to 110 calendar days after discovery of the failure.	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days, but less than or equal to 120 calendar days after discovery of the failure. OR The ~~Transmission Owner or~~	The ~~Transmission Owner or~~ Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and failed to provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR ~~Transmission Owner or~~ The Generator Owner as directed by

		Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-028-1, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Technical Rationale for Reliability Standard PRC-028-1

July 2024

PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter Based Resources

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for Inverter-Based Resources to aid with event analysis, performance monitoring, and disturbance-based Inverter-Based Resource model validation. These disturbance reports are recommended to install disturbance monitoring equipment (DME) at wind and solar photovoltaic (PV) resources to ensure adequate data is available for event analysis, performance monitoring, and validating Inverter-Based Resource models. The recommendation included plant-level high resolution oscillography data, plant SCADA data with a resolution of one second, and inverter level of sequence of events recording data that include all fault codes and high resolution oscillography data. In a first version of this standard, only SER data at inverter level data is required. For the purposes of this standard, the inverter, converter, wind turbine generator, or high voltage direct current converter connecting generating resource to alternating current Transmission network is referred to as an IBR unit.

The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. The recent disturbance analyses of events involving inverter-bases resources (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have demonstrated that Inverter-Based Resource's response to a normally cleared few cycle fault is undesirable and poses risk to system reliability. All these disturbance analyses have identified that Inverter-Based Resources involved did not have sufficient monitoring data to understand the plants' responses. The initiating event, e.g., a normally cleared transmission fault, was not a large-scale system disturbance; however, Inverter-Based Resource's undesirable response due to a system fault resulted in a larger system disturbance. Adequate monitoring data is required to understand Inverter-Based Resource's performance. Most of the Inverter-Based Resources involved in these disturbances did not have and were not required to have adequate disturbance monitoring data. The lack of disturbance monitoring data available from these facilities led to difficulty in adequately assessing the events. Introducing Inverter-Based Resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for Inverter-Based Resources is created instead of revising the Reliability Standard PRC-002.

The Generator Owners, as applicable, will have the responsibility for ensuring that adequate data is available for applicable Elements at the applicable Inverter-Based Resources. This standard requires that sequence of events recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data is available from the applicable Inverter-Based Resources.

Rationale for Applicability Section
Functional Entities
The functional entity that is responsible for implementing disturbance monitoring equipment and collecting recording data is Generator Owner.

Applicable Facilities
The BES Inverter-Based Resources and Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV, are in the scope of this standard.

Order No. 901 directed NERC to develop Reliability Standards “to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners’ disturbance monitoring equipment.” Order No. 901 at P 85. FERC continued, “We further agree with the findings in NERC reports (e.g., a lack of high-speed data captured at the IBR or plant-level controller and low-resolution time stamping of inverter sequence of event recorder information has hindered event analysis) and direct NERC through its standard development process to address these findings.”

In distinguishing among the different types of IBRs and their registration status that must be covered by the standards, FERC stated: “Where necessary to describe our directives, however, we differentiate between IBRs registered with NERC (or which will be registered pursuant to the Commission’s directives in Registration of Inverter-based Resources, 181 FERC ¶ 61,124 (2022) (IBR Registration Order)) and therefore subject to the Reliability Standards (i.e., registered IBR), IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards (i.e., unregistered IBRs), and IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk Power System (i.e., IBR-DER).” Order No. 901 at n. 14.

In proposed PRC-028-1, the standard drafting team includes both categories of generation that would be registered under proposed changes to NERC Rules of Procedure consistent with Order No. 901. In February 2024, the NERC Board of Trustees approved revisions to the Rules of Procedure to expand the Generator Owners and Generator Operators registered with NERC for compliance purposes. In addition to owners and operators of generating Facilities, NERC will register owners and operators of sub-BES IBRs meeting the following criteria: non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. On June 27, 2024, FERC issued an order approving NERC's proposed revisions to its Rules of Procedure, subject to NERC submitting a compliance filing, under section 215 of the Federal Power Act.

The following Elements associated with Inverter-Based Resources noted above are in the scope of this standard:

- Circuit breaker(s) (or interrupting devices)
- Main power transformer(s)
- Collector bus
- Shunt static or dynamic reactive device(s)[1], including any filter banks,
- AC-DC and DC-AC converters, if any, in case of VSC HVDC line with a dedicated connection to Inverter-Based Resource

The following examples are provided to clarify applicability of the PRC-028 standard.

Example 1: Applicability of PRC-028

Figure 1 shows a typical single line diagram of an Inverter-Based Resource. The Inverter-Based Resource is connected to the transmission system via a short tie-line. This Inverter-Based Resource is equipped with a dynamic reactive device (e.g., synchronous condenser, static VAR compensator etc.) connected to the collector bus.

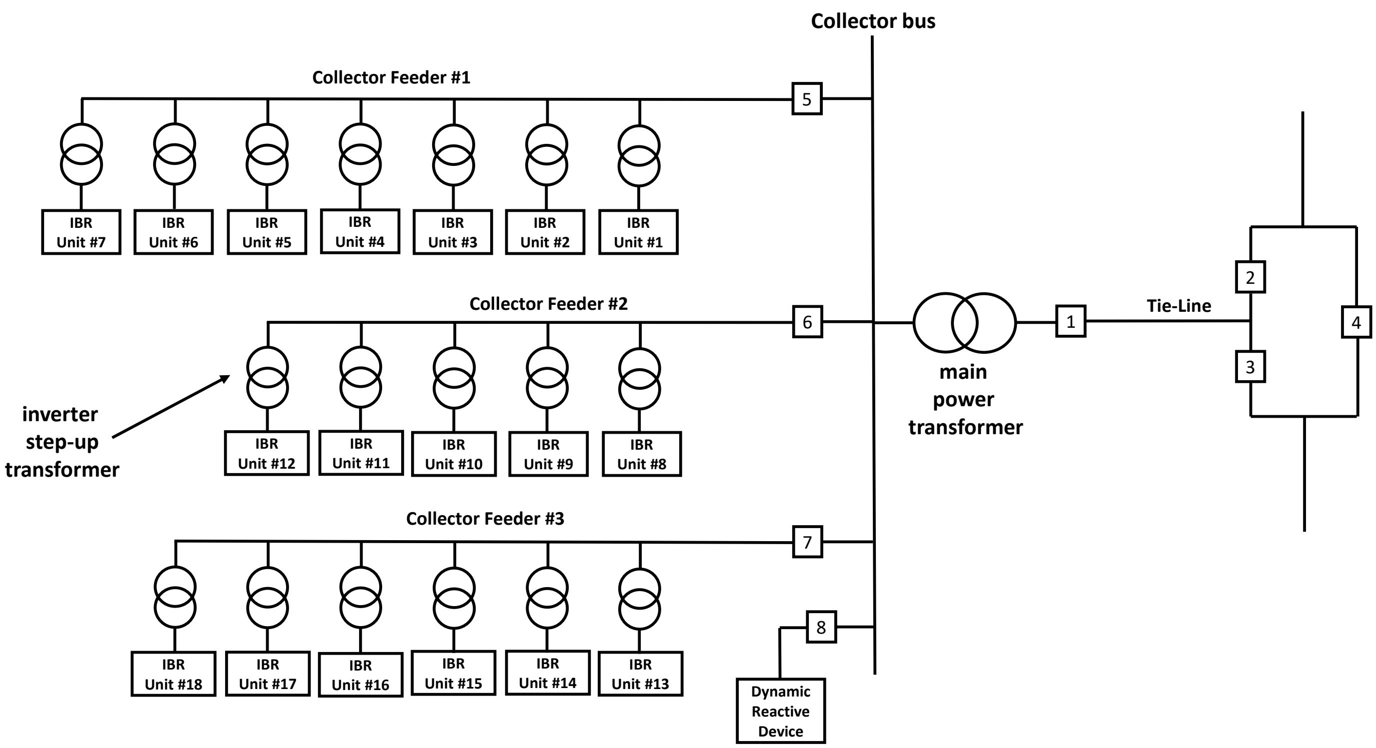


Figure 1: Typical Inverter-Based Resource Single Line Diagram

[1] Synchronous condensers when installed within the Inverter-Based Resource are considered shunt dynamic reactive devices.

SER Data: The SER data is required for circuit breakers 1, 5, 6, 7, and 8. Circuit breaker 1 is associated with the main power transformer. Circuit breakers 5, 6, 7, and 8 are associated with the collector bus. The SER data from all IBR units is required.

FR Data: The FR data is required from high side terminals of the main power transformer. In this example, the Inverter-Based Resource consists of only one main power transformer. If the Inverter-Based Resource consists of more than one main power transformer, then FR data for each main power transformer is required. As the Inverter-Based Resource is equipped with the dynamic reactive device, the FR data for it is also required. The FR data from collector feeder circuit breakers 5, 6, and 7 is also required.

DDR Data: The DDR data is required from high side terminals of the main power transformer. If the Inverter-Based Resource consists of more than one main power transformer, then DDR data for each main power transformer is required.

Example 2: Applicability of PRC-028 (Facility with two collector buses and main power transformers)

Figure 2 shows a single line diagram of an Inverter-Based Resource with two collector buses and main power transformers. The Inverter-Based Resource is connected to the transmission system via a short tie-line. The collector feeders #1 and #2 are connected to collector bus #1. The collector feeders #3 and #4 are connected to collector bus #2.

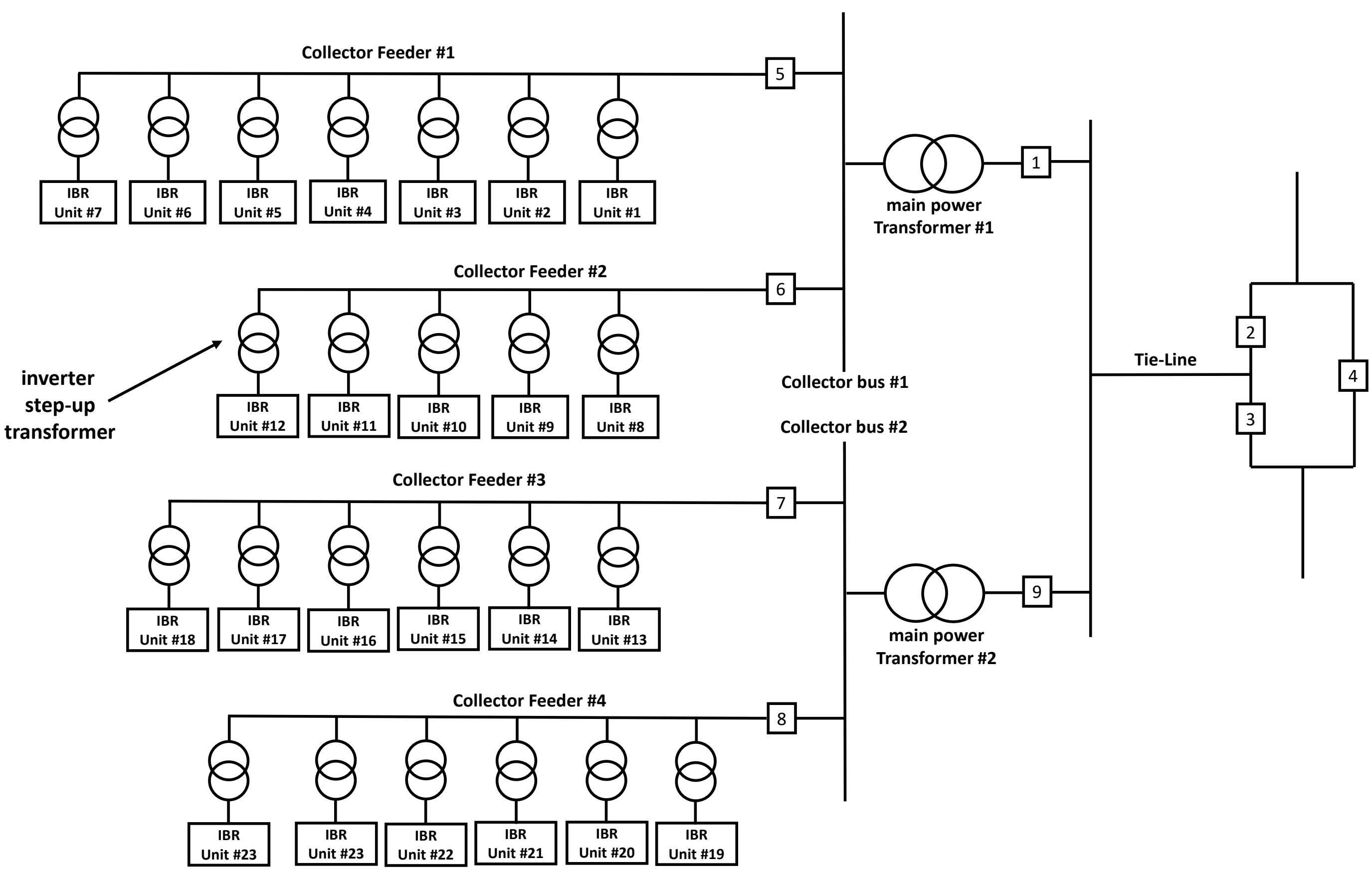


Figure 2: Typical Inverter-Based Resource with two collector buses and main power transformers

SER Data: The SER data is required for circuit breakers 1, 5, 6, 7, 8, and 9. Circuit breakers 1 and 9 are associated with main power transformers. Circuit breakers 5, 6, 7, and 8 are associated with collector buses #1 and #2. The SER data from all IBR units is required.

FR Data: The FR data is required from high side terminals of both main power transformers. The FR data from collector feeder circuit breakers 5, 6, 7, and 8 is also required.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 3: Applicability of PRC-028 (VSC HVDC system with a dedicated connection to Inverter-Based Resources)

Figure 3 shows an example of dedicated VSC HVDC system connecting the Inverter-Based Resource[2]. Transformers on both sides of the HVDC system are considered main power transformer.

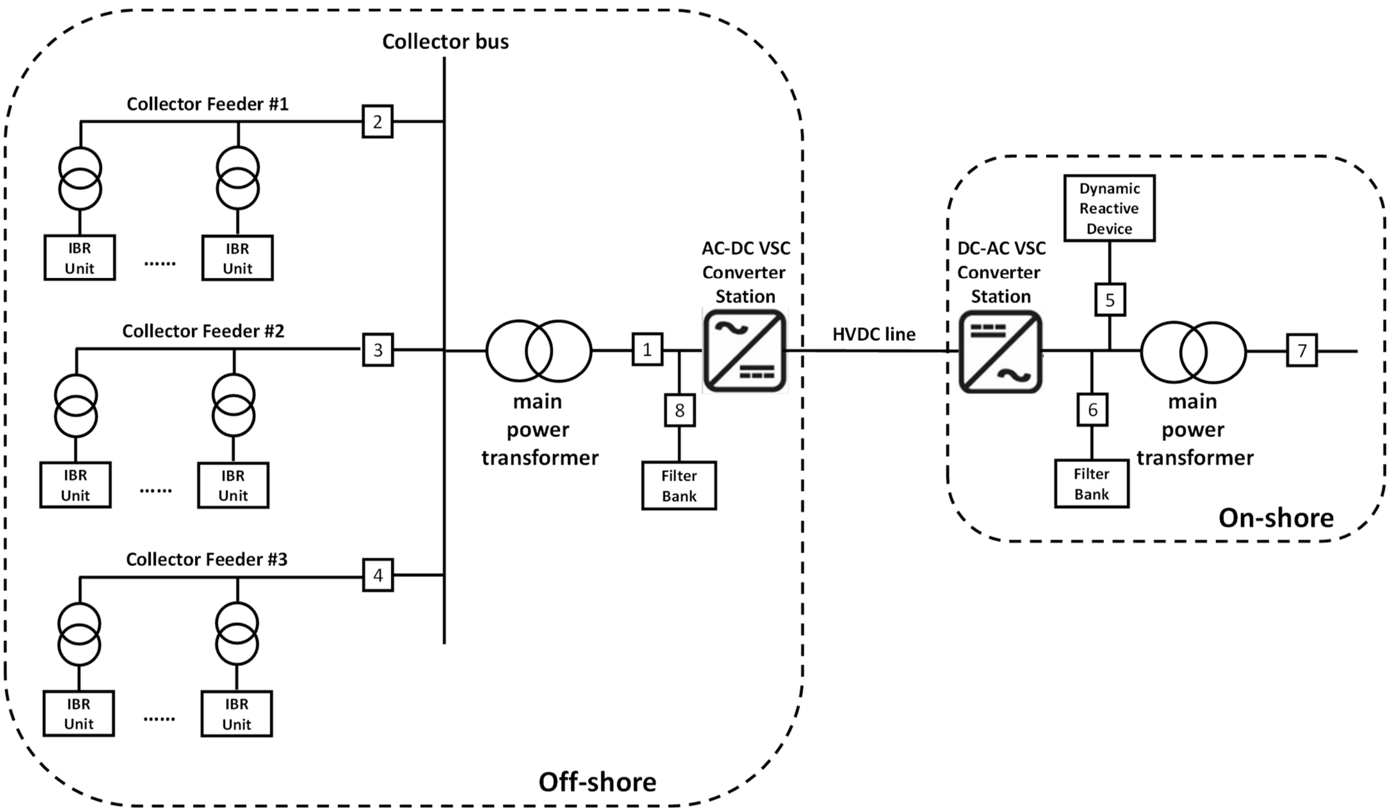


Figure 3: Typical Inverter-Based Resource connected via dedicated VSC HVDC

[2] Refer to Technical Rationale Project 2020-06 Verification of Models and Data for Generators Inverter-based Resource Definition available at: https://www.nerc.com/pa/Stand/Project_2020_06_Verifications_of_Models_and_Data_f/2020-06_IBR_Definition_Technical_Rationale_Clean_07122024.pdf.

SER Data: The SER data is required for circuit breakers 1, 2, 3, 4, 5, 6, 7, and 8. Circuit breakers 1 and 7 are associated with main power transformers. Circuit breakers 2, 3, and 4 are associated with the collector bus. Circuit breakers 6 and 8 are associated with filter banks and circuit breaker 5 is associated with shunt dynamic reactive device. The SER data from all IBR units is required.

FR Data: The FR data is required from high side terminals of both main power transformers. The FR data from collector feeder circuit breakers 2, 3, and 4 is also required.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 4: Applicability of PRC-002 versus PRC-028

Figure 4 shows an example of Inverter-Based Resource interconnection to the transmission system via Line 34. The BES bus in substation Wu is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for the identified BES bus are per the requirements in the Reliability Standard PRC-002. The Reliability Standard PRC-028 is applicable to the Inverter-Based Resource.

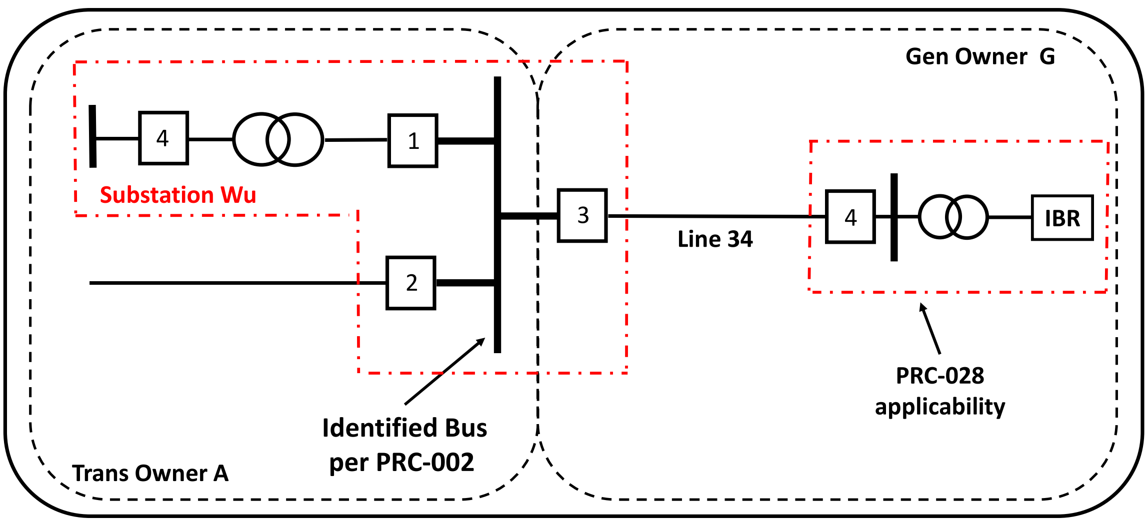


Figure 4: Inverter-Based Resource Interconnection – Applicability of PRC-002 versus PRC-028

Rationale for Requirement R1

The standard is required to capture SER data from circuit breakers within the Inverter-Based Resource associated with:

- Main power transformer(s)
- Collector bus(es), including collector feeder breakers
- Shunt static or dynamic reactive device(s), including any filter banks
- AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to Inverter-Based Resources.

The standard also requires capturing SER data from all IBR units. However, it is recognized that for IBR units in commercial operation before the effective date of this standard, IBR units may not be capable to capture SER data. If IBR unit is in commercial operation before the effective date of this standard and not capable to capture SER data then SER data is not required. The SER data required from IBR units are as follows: all fault codes and alarms, high and low voltage/frequency ride-through mode status.

Change of state of circuit breaker position and IBR unit SER data, time stamped according to Requirement R7 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of Inverter-Based Resource's response during a power System disturbance. Analyses of system disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations helps determine the interruption of flows during the disturbances.

Rationale for Requirement R2

The intent is to capture sufficient FR data for Elements at each Inverter-Based Resource to analyze the overall response of the Inverter-Based Resource to a system disturbance. Analyses of disturbances involving widespread reduction of power output from Inverter-Based Resources in recent years has shown that expansion of monitoring at Inverter-Based Resource sites is necessary. The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g., residual or neutral current if the phase currents are directly measured).

The FR data captured from IBR units helps in understanding individual IBR unit's response during system disturbances. However, in lieu of requiring FR data from IBR units, standard requires FR data from collector feeder breakers. The FR data captured from collector feeder breakers provides information about collective response of IBR units on a given collector feeder during system disturbances.

The plant level FR measurements, i.e., measured on high-side terminals of the main power transformer, specified in Requirement R2, Part 2.1 provide data at the Inverter-Based Resource interconnection to the bulk power system. To cover all possible fault types, phase-to-neutral voltage recording for each phase is required to be determinable. Each phase current and residual current are required to distinguish between phase faults and ground faults. This data also facilitates determination of the fault location and cause of relay operation. The measurements of active and reactive power provide data on the overall generating facility's response to the system disturbance.

In some cases, the dynamic reactive device is used within the Inverter-Based Resource and often connected to medium voltage collector bus. Regardless of where dynamic reactive device is connected, the output of it during system disturbances is important to understand overall performance of the plant during a disturbance. The measured or determined electrical quantities for dynamic reactive device are same as those specified to be measured/determined from high-side of main power transformer.

<u>Recording of Electrical Quantities</u>

For effective fault analysis, it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments

SERs in evaluating circuit breaker operation. FR also shows generator output response to a system disturbance.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120 degrees, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current Ir, is calculated as a sum of vectors of three phase currents:

$$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable Elements as outlined in Requirement R2.

Rationale for Requirement R3

Time stamped pre- and post-trigger FR data aid in the analysis of power system operations and determination if operations were as intended.

The “Odessa Disturbance” report from September 2021 recommended high resolution oscillography data at the point of interconnection. The minimum recording rate of 64 samples per cycle is specified recognizing state-of-the-art for DME including storage any storage capability limitations and provides sufficient data to recreate accurate response of the Inverter-Based Resource to system disturbances.

Pre- and post-trigger fault data along with the SER data, all time stamped to a common clock, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Additionally, Inverter-Based Resources employ fast acting control systems (with built in protection functions) dictating Inverter-Based Resource’s response to system disturbance. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles. To capture the full response of Inverter-Based Resource spread over a large geographic area, a 2 second total minimum record length synchronized to a common clock is necessary for FR data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data but are not capable of providing fault data in a single record with 120 continuous cycles total.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R3, Part 3.1.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R3, sub-Part 3.1.3.2 specifies a phase overvoltage or undervoltage trigger during voltage ride-through events.

The triggers specified in Requirement R3, Part 3.3 for dynamic reactive device FR data are similar to ones specified in Requirement R3, Part 3.1 for plant level FR data measured or determined on high-side of the main power transformer.

Rationale for Requirement R4

Large scale system disturbances generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and Inverter-Based Resource's response to large scale system disturbances. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event. The state-of-the-art DDR equipment is capable of continuous recording.

DDR data contains the dynamic response of the Inverter-Based Resource to a system disturbance and is used for analyzing complex power system events. This recording is typically used to capture short-term and long-term disturbances. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

DDR is used to measure transient response to system disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage and current from the same phase or positive sequence for each applicable main power transformer for analysis. It is also sufficient to provide a single frequency for any of the provided voltages since all main power transformers within an Inverter-Based Resource are at the same frequency. Recording of all three phases of voltage/current is not required, although this may be used to compute and record the positive sequence value(s). The electrical quantities for Real Power and Reactive Power on a three-phase basis can be measured/recorded or determined (calculated, derived, etc.).

The data requirements for PRC-028-1 are based on a system configuration assuming all normally closed circuit breakers on a BES bus are closed.

A crucial part of disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary to have DDR on high-side of the main power transformer(s) measuring the specified electrical quantities to adequately capture Inverter-Based Resource's response.

The Requirement R4, Part 4.1 requires either one phase-to-neutral or positive sequence voltage. However, the phase-to-phase voltage recording is acceptable. Since the BES operates under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Rationale for Requirement R5

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltages and frequency. The input sampling rate specified is same as one specified in the Reliability Standard PRC-002.

An output recording rate of electrical quantities of at least 60 times per second refers to the recording rate of the device. Recorded measurements of at least 60 times per second provide adequate recording speed to monitor the Inverter-Based Resource's response during power system disturbances. Since control system associated with Inverter-Based Resources is fast acting, higher frequency recording is necessary to accurately reconstruct events. An output recording rate of 60 times per second provides this higher frequency recording while not greatly increasing data storage requirements.

Rationale for Requirement R6

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 1 millisecond accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 1 millisecond accuracy will suffice with respect to providing time synchronized data. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. Note that the recently published IEEE Std 2800 requires the DME recording plant level data be synchronized to the clock with accuracy of ± 1 microsecond accuracy; however, the accuracy requirement is set to ± 1 millisecond to strike a balance between need of accuracy and practical limitations of equipment necessary to achieve the stated accuracy. Recognizing challenges with distributing synchronizing clock signal to all IBR units with the Inverter-Based Resource, the IBR units (for capturing of SER data) are required to have synchronized device clock accuracy within ± 100 milliseconds of UTC.

The Inverter-Based Resources, which are not affected by inertial time constants, make changes in power production very rapidly. To understand and analyze control decisions during system disturbances and the reasons behind them over dozens of plants requires a high level of accurate time synchronization. The following provide some examples of Inverter-Based Resource's fast response:

- Typical 90% response to a three-phase fault is < 40 ms.
- Central power plant controllers issue updated commands in as little as 40 ms upon detection of change in system conditions.
- Standard closed loop voltage control response can be <200 ms.

- Instantaneous Inverter protective trip decisions such as AC or DC overvoltage or reverse DC current can be made in less than 10 ms.

Rationale for Requirement R7

Requirement R7, Part 7.1 specifies a minimum time period of 20 calendar days inclusive of the day the data was recorded for which the data is to be retrievable. Data hold requests are usually initiated the same or next day following a major event, however, it takes a longer time to determine which data from which generating facility needs to be retrieved for event analysis. A 20 calendar day time period provides enough time for communication between various Entities regarding the event and need for data retrieval from DME at various generating facilities. The requestor of data has to be aware of 20 calendar day retrievability limit to ensure timely data hold requests. Requiring data retention for a longer period of time is expensive and unnecessary.

With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 20 days. To clarify the 20 calendar day time frame, let's assume that event occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 20 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 21, that is outside the 20 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER, FR and DDR data for generating facilities as per the applicability. To facilitate the analysis of system disturbances, it is important that the data is provided to the requestor within a reasonable time. Providing the data within 15 calendar days (or the granted extension time), subject to Requirement R7, Part 7.2, allows for reasonable time to collect the data and perform any necessary computations or formatting. An entity may request an extension of the 15 calendar days submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Disturbance analysis includes reviewing data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improve timely analysis. The formatting and naming convention requirements for SER, FR, and DDR are consistent with same requirements in the Reliability Standard PRC-002.

SER data: Requirement R7, Part 7.3 specifies a simple ASCII Comma Separated Value (CSV) format according to Attachment 1. It is necessary to establish a standard format as it allows data submitted by one entity or facility to be incorporated with same data provided by other entities or facilities to develop a detailed sequence of events timeline of a power system disturbance.

FR data: Requirement R7, Part 7.4 specifies either CSV format with appropriate headers or the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the FR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources.

DDR data: Requirement R7, Part 7.5 specifies either CSV format with appropriate headers or the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the DDR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources.

The 2013 revision of the IEEE C37.111 includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R7, Part 7.6 specifies the IEEE C37.232 Standard for Common Format for Naming Time Sequence Data Files (COMNAME) format for naming the SER, FR, and DDR data files. The lack of a common naming practice seriously hinders the event analysis and investigation process.

Rationale for Requirement R8

The standard requires that Entity restore the recording capability for SER, FR, or DDR data within 90 calendar days of the discovery of a failure. The 90 calendar day time period permitted in this requirement strikes a balance between reasonable time needed to restore capability while ensuring that recording capability is not out of service for an extended duration. If the recording capability cannot be restored within 90 calendar days due to limitations such as budget cycle, service crews, vendors, needed outages, etc., the entity is required to submit a Corrective Action Plan for restoring the recording capability to the Regional Entity and implement it. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored Element does not constitute a failure of the disturbance monitoring capability.

Technical Rationale for Reliability Standard PRC-028-1

July 2024

PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter Based Resources

The recent disturbance reports (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have identified a need for disturbance monitoring for ~~inverter-based resource~~Inverter-Based Resources~~[1]~~ to aid with event analysis, performance monitoring, and disturbance-based ~~inverter-based resource~~Inverter-Based Resource model validation. These disturbance reports are recommended to install disturbance monitoring equipment (DME) at wind and solar photovoltaic (PV) resources to ensure adequate data is available for event analysis, performance monitoring, and validating ~~inverter-based resource~~Inverter-Based Resource models. The recommendation included plant-level high resolution oscillography data, plant SCADA data with a resolution of one second, and inverter level of sequence of events recording data that include all fault codes and high resolution oscillography data. ~~However, i~~In a first version of this standard, only SER data ~~recording of~~ at inverter level data is ~~not~~ required. For the purposes of this standard, the inverter, converter, wind turbine generator, or high voltage direct current converter connecting generating resource to alternating current Transmission network is referred to as an IBR unit.

The purpose of Reliability Standard PRC-002 is to capture event data to understand large scale system disturbances occurring on the Bulk Electric System (BES). Even with changing resource mix, the Reliability Standard PRC-002 serves the purpose. The recent disturbance analyses of events involving inverter-bases resources (e.g., Blue Cut Fire, Canyon 2 Fire, Odessa disturbances) have demonstrated that ~~inverter-based resource~~Inverter-Based Resource's response to a normally cleared few cycle fault is undesirable and poses risk to system reliability. All these disturbance analyses have identified that ~~inverter-based resource~~Inverter-Based Resources involved did not have sufficient monitoring data to understand the plants' responses. The initiating event, e.g., a normally cleared transmission fault, was not a large-scale system disturbance; however, ~~inverter-based resource~~Inverter-Based Resource's undesirable response due to a system fault resulted in a larger system disturbance. Adequate monitoring data is required to understand ~~inverter-based resource~~Inverter-Based Resource's performance. Most of the ~~inverter-based resource~~Inverter-Based Resources involved in these disturbances did not have and were not required to have adequate disturbance monitoring data. The lack of disturbance monitoring data available from these

~~[1] For the purpose of this standard, "inverter-based resource~~Inverter-Based Resources~~" refers to a collection of individual solar photovoltaic (PV), Type 3 and Type 4 wind turbines, battery energy storage system (BESS), or fuel cells that operate as a single plant/resource. In case of offshore wind plants connecting via a dedicated voltage source converter high voltage direct current (VSC HVDC) line, the inverter-based resource~~Inverter-Based Resource ~~includes VSC HVDC line.~~

facilities led to difficulty in adequately assessing the events. Introducing ~~inverter-based resource~~Inverter-Based Resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, to address needs identified in the Standard Authorization Request (SAR) submitted by the ~~Inverter-Based Resource~~Inverter-Based Resource Performance Task Force (IRPTF), a new standard for monitoring requirements for ~~inverter-based resource~~Inverter-Based Resources is created instead of revising the Reliability Standard PRC-002.

The ~~Transmission Owners and~~ Generator Owners, as applicable, will have the responsibility for ensuring that adequate data is available for applicable Elements at the applicable ~~inverter-based resource~~Inverter-Based Resources. This standard requires that sequence of events recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data is available from the applicable ~~inverter-based resource~~Inverter-Based Resources.

Rationale for Applicability Section

Functional Entities

The ~~two~~ functional entity~~entities~~ that is~~are~~ responsible for implementing disturbance monitoring equipment and collecting recording data is~~are:~~ Generator Owner~~ and Transmission Owner~~. ~~The standard is only applicable to Transmission Owner in cases where Transmission Owner owns equipment (e.g., circuit breaker(s), main step-up transformer, collector bus, dynamic reactive device, etc.) within the inverter-based resourceInverter-Based Resource.~~

Applicable Facilities

~~The BES inverter-based resourceInverter-Based Resources are in the scope of this standard.~~

The BES Inverter-Based Resources and Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV, are in the scope of this standard.

Order No. 901 directed NERC to develop Reliability Standards "to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment." Order No. 901 at P 85. FERC continued, "We further agree with the findings in NERC reports (e.g., a lack of high-speed data captured at the IBR or plant-level controller and low-resolution time stamping of inverter sequence of event recorder information has hindered event analysis) and direct NERC through its standard development process to address these findings."

In distinguishing among the different types of IBRs and their registration status that must be covered by the standards, FERC stated: "Where necessary to describe our directives, however, we differentiate between IBRs registered with NERC (or which will be registered pursuant to the Commission's directives in

Registration of Inverter-based Resources, 181 FERC ¶ 61,124 (2022) (IBR Registration Order)) and therefore subject to the Reliability Standards (i.e., registered IBR), IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards (i.e., unregistered IBRs), and IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk Power System (i.e., IBR-DER)." Order No. 901 at n. 14.

In proposed PRC-028-1, the standard drafting team includes both categories of generation that would be registered under proposed changes to NERC Rules of Procedure consistent with Order No. 901. In February 2024, the NERC Board of Trustees approved revisions to the Rules of Procedure to expand the Generator Owners and Generator Operators registered with NERC for compliance purposes. In addition to owners and operators of generating Facilities, NERC will register owners and operators of sub-BES IBRs meeting the following criteria: non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. On June 27, 2024, FERC issued an order approving NERC's proposed revisions to its Rules of Procedure, subject to NERC submitting a compliance filing, under section 215 of the Federal Power Act.

The following Elements associated with ~~inverter-based resource~~Inverter-Based Resources noted above are in the scope of this standard:

- Circuit breaker(s) (or interrupting devices)
- Main power transformer(s)
- Collector bus
- Shunt static or dynamic reactive device(s)[2], including any filter banks,
- AC-DC and DC-AC converters, if any, in case of VSC HVDC line with a dedicated connection to ~~inverter-based resource~~Inverter-Based Resource~~s~~
-

The following examples are provided to clarify applicability of the PRC-028 standard.

Example 1: Applicability of PRC-028

Figure 1 shows a typical single line diagram of an ~~inverter-based resource~~Inverter-Based Resource. The ~~inverter-based resource~~Inverter-Based Resource is connected to the transmission system via a short tie-line. This ~~inverter-based resource~~Inverter-Based Resource is equipped with a dynamic reactive device (e.g., synchronous condenser, static VAR compensator etc.) connected to the collector bus.

[2] Synchronous condensers when installed within the Inverter-Based Resource are considered shunt dynamic reactive devices.

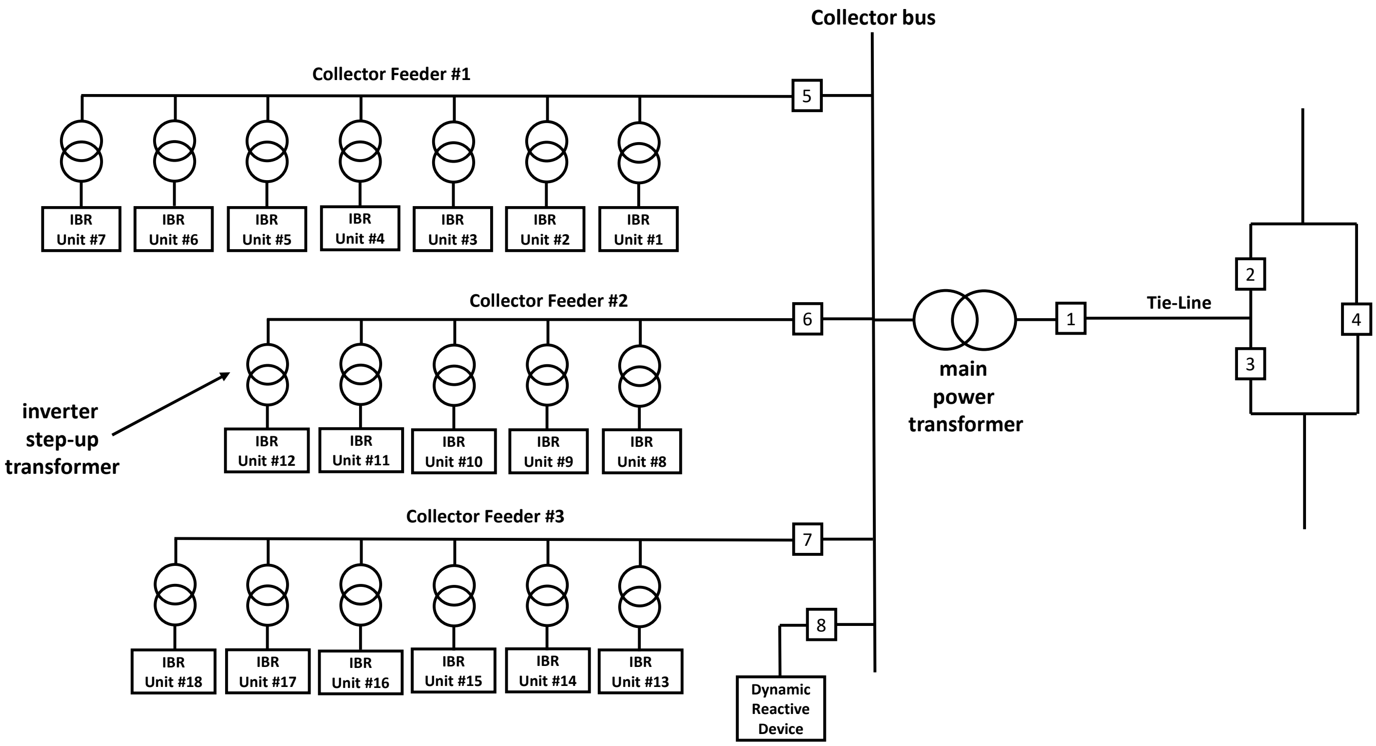


Figure 1: Typical ~~inverter-based resource~~Inverter-Based Resource Single Line Diagram

SER Data: The SER data is required for circuit~~s~~ breakers 1, 5, 6, 7, and 8. Circuit breaker 1 is associated with the main power transformer. Circuit breakers 5, 6, 7, and 8 are associated with the collector bus. The SER data from all IBR units is required.

FR Data: The FR data is required from high side terminals of the main power transformer. In this example, the ~~inverter-based resource~~Inverter-Based Resource consists of only one main power transformer. If the ~~inverter-based resource~~Inverter-Based Resource consists of more than one main power transformer, then FR data for each main power transformer is required. As the ~~inverter-based resource~~Inverter-Based Resource is equipped with the dynamic reactive device, the FR data for it is also required. The FR data from collector feeder circuit breakers 5, 6, and 7 is also required.

DDR Data: The DDR data is required from high side terminals of the main power transformer. If the ~~inverter-based resource~~Inverter-Based Resource consists of more than one main power transformer, then DDR data for each main power transformer is required.

Example 2: Applicability of PRC-028 (Facility with two collector buses and main power transformers)

Figure 2 shows a single line diagram of an ~~inverter-based resource~~Inverter-Based Resource with two collector buses and main power transformers. The ~~inverter-based resource~~Inverter-Based Resource is connected to the transmission system via a short tie-line. The collector feeders #1 and #2 are connected to collector bus #1. The collector feeders #3 and #4 are connected to collector bus #2.

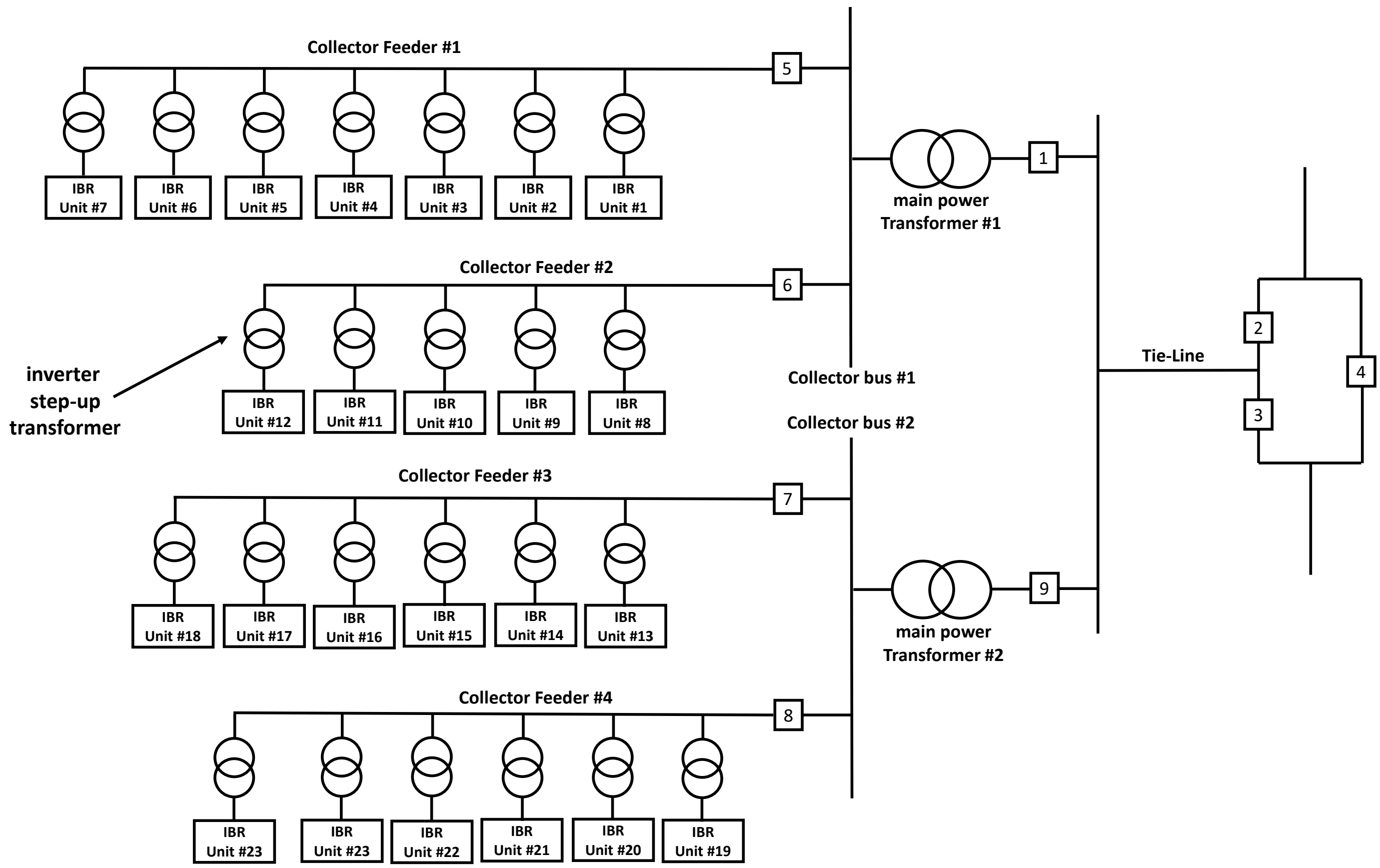


Figure 2: Typical ~~inverter-based resource~~Inverter-Based Resource with two collector buses and main power transformers

SER Data: The SER data is required for circuit~~s~~ breakers 1, 5, 6, 7, 8, and 9. Circuit breakers 1 and 9 are associated with main power transformers. Circuit breakers 5, 6, 7, and 8 are associated with collector buses #1 and #2. The SER data from all IBR units is required.

FR Data: The FR data is required from high side terminals of both main power transformers. The FR data from collector feeder circuit breakers 5, 6, 7, and 8 is also required.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 3: Applicability of PRC-028 (VSC HVDC system with a dedicated connection to ~~inverter-based resource~~Inverter-Based Resources)

Figure 3 shows an example of dedicated VSC HVDC system connecting the ~~inverter-based resource~~Inverter-Based Resource[3]. Transformers on both sides of the HVDC system are considered main power transformer.

[3] Refer to Technical Rationale Project 2020-06 Verification of Models and Data for Generators Inverter-based Resource Definition available at: https://www.nerc.com/pa/Stand/Project_2020_06_Verifications_of_Models_and_Data_f/2020-06_IBR_Definition_Technical_Rationale_Clean_07122024.pdf.

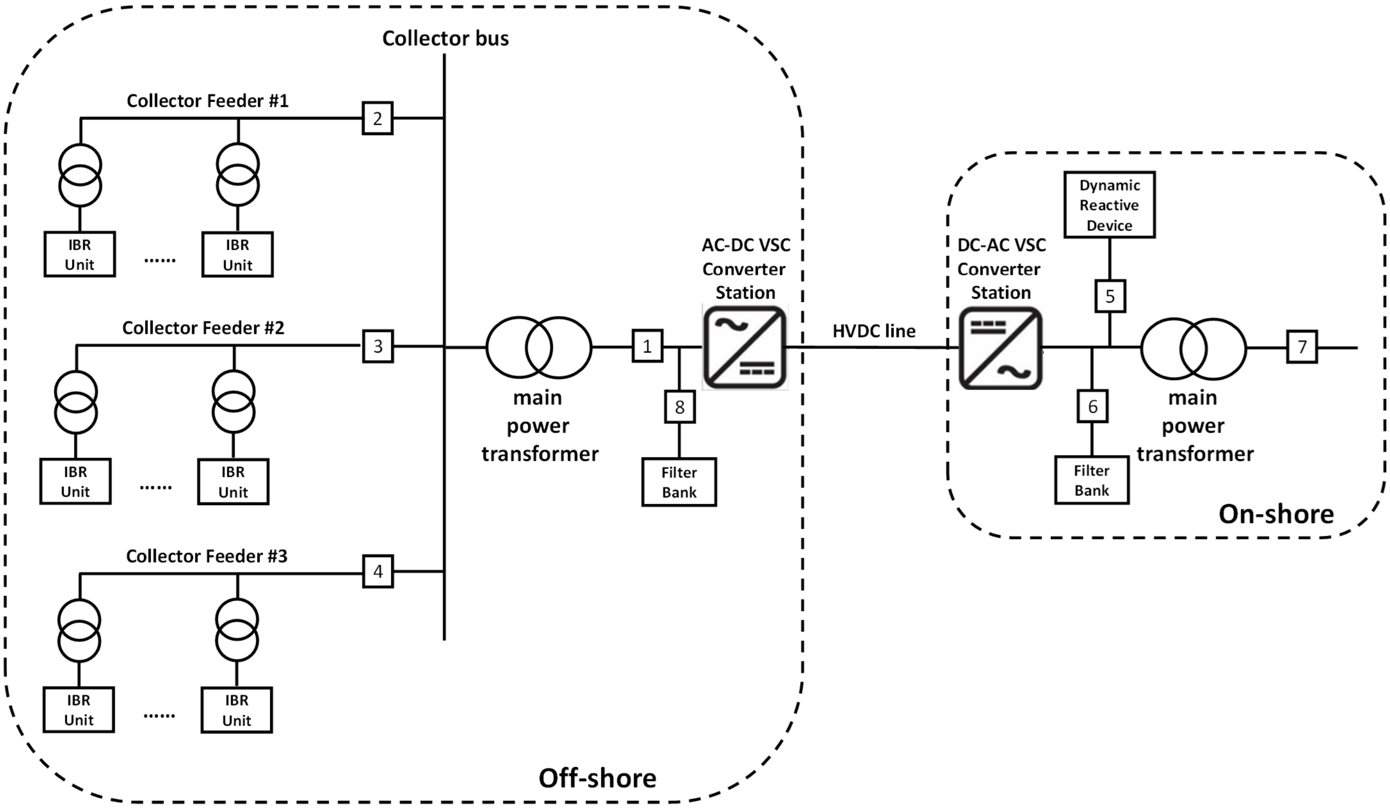


Figure 3: Typical ~~inverter-based resource~~Inverter-Based Resource connected via dedicated VSC HVDC

SER Data: The SER data is required for circuit~~s~~ breakers 1, 2, 3, 4, 5, 6, 7, and 8. Circuit breakers 1 and 7 are associated with main power transformers. Circuit breakers 2, 3, and 4 are associated with the collector bus. Circuit breakers 6 and 8 are associated with filter banks and circuit breaker 5 is associated with shunt dynamic reactive device. The SER data from all IBR units is required.

FR Data: The FR data is required from high side terminals of both main power transformers. The FR data from collector feeder circuit breakers 2, 3, and 4 is also required.

DDR Data: The DDR data is required from high side terminals of both main power transformers.

Example 4: Applicability of PRC-002 versus PRC-028

Figure 4 shows an example of ~~inverter-based resource~~Inverter-Based Resource interconnection to the transmission system via Line 34. The BES bus in substation Wu is the identified BES bus per methodology in Attachment 1 of the Reliability Standard PRC-002. The SER and FR data requirements for the identified BES bus are per the requirements in the Reliability Standard PRC-002. The Reliability Standard PRC-028 is applicable to the ~~inverter-based resource~~Inverter-Based Resource.

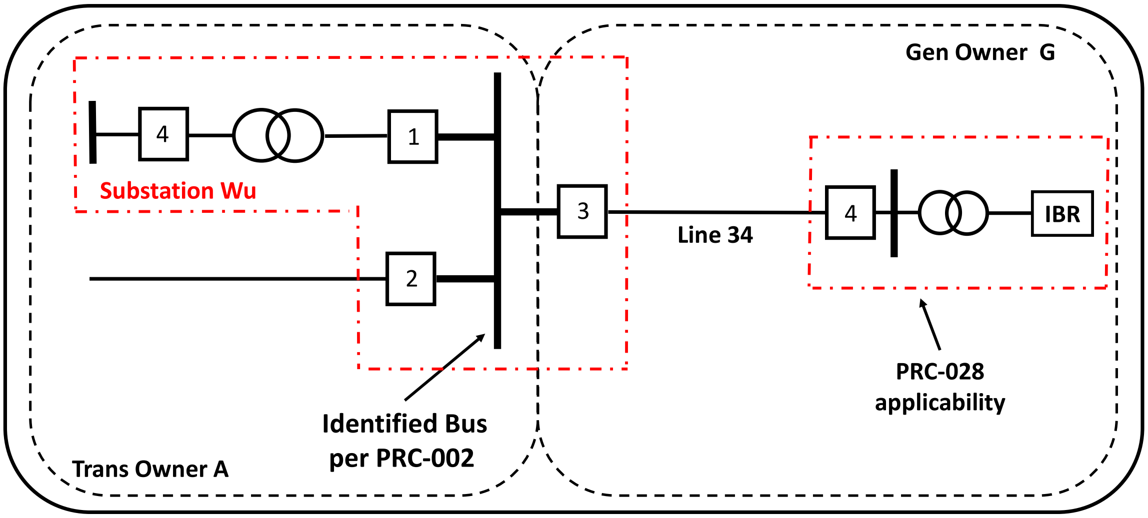
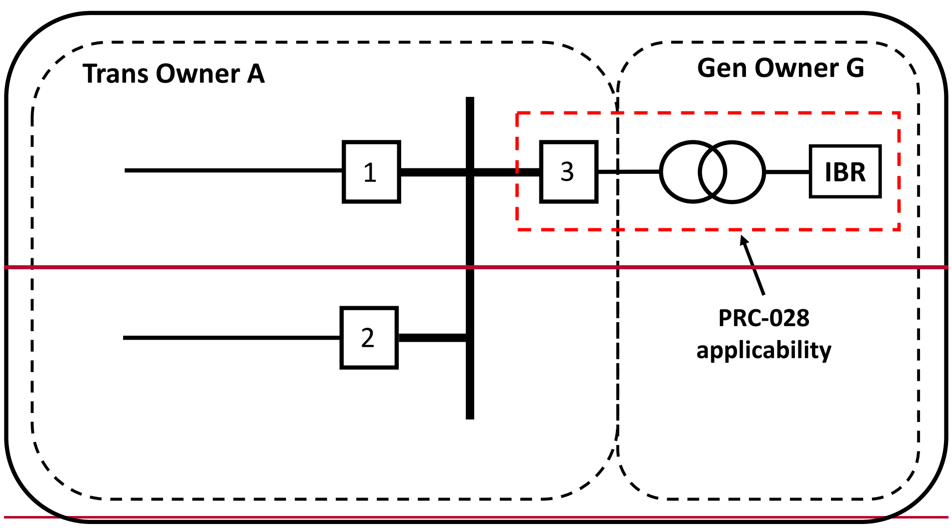


Figure 4: ~~Inverter-based resource~~Inverter-Based Resource Interconnection – Applicability of PRC-002 versus PRC-028

~~Example 5: Transmission Owner owned Equipment within the inverter-based resourceInverter-Based Resource~~

~~Figure 5 shows an example of an inverter-based resourceInverter-Based Resource interconnection where Transmission Owner A owns circuit breaker 3 associated with an inverter-based resourceInverter-Based Resource. In this case, Transmission Owner A is responsible for SER data for circuit breaker 3. It is not common for Transmission Owner to own the main power transformer and/or portions of collector system associated with an inverter-based resourceInverter-Based Resource. However, in cases where this is true, Transmission Owner is responsible for SER, FR, and DDR data, as applicable, required by the Reliability Standard PRC-028.~~



~~Figure 5: Transmission Owner owned Equipment within an inverter-based resourceInverter-Based Resource~~

Rationale for Requirement R1

The standard is requireds to capture SER data from circuit breakers within the ~~inverter-based resource~~Inverter-Based Resource associated with:

- Main power transformer(s)
- Collector bus(es), including collector feeder breakers
- Shunt static or dynamic reactive device(s), including any filter banks
- AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to ~~inverter-based resource~~Inverter-Based Resources.

The standard also requires capturing SER data from all IBR units. However, it is recognized that for IBR units in commercial operation before the effective date of this standard, IBR units may not be capable to capture SER data. If IBR unit is in commercial operation before the effective date of this standard and not capable to capture SER data then SER data is not required. The SER data required from IBR units are as follows: all fault codes and alarms, high and low voltage/frequency ride-through mode status.

Change of state of circuit breaker position and IBR unit SER data, time stamped according to Requirement R7 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of ~~inverter-based resource~~Inverter-Based Resource's response during a power System disturbance. Analyses of system disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations helps determine the interruption of flows during the disturbances.

Rationale for Requirement R2

The intent is to capture sufficient FR data for Elements at each ~~inverter-based resource~~Inverter-Based Resource to analyze the overall response of the ~~inverter-based resource~~Inverter-Based Resource to a system disturbance. Analyses of disturbances involving widespread reduction of power output from ~~inverter-based resource~~Inverter-Based Resources in recent years has shown that expansion of monitoring at ~~inverter-based resource~~Inverter-Based Resource sites is necessary. The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g., residual or neutral current if the phase currents are directly measured).

The FR data captured from IBR units helps in understanding individual IBR unit's response during system disturbances. However, in lieu of requiring FR data from IBR units, standard requires FR data from collector feeder breakers. The FR data captured from collector feeder breakers provides information about collective response of IBR units on a given collector feeder during system disturbances.

The plant level FR measurements, i.e., measured on high-side terminals of the main power transformer, specified in Requirement R2, Part 2.1 provide data at the ~~inverter-based resource~~Inverter-Based Resource interconnection to the bulk power system. To cover all possible fault types, phase-to-neutral voltage recording for each phase is required to be determinable. Each phase current and residual current are required to distinguish between phase faults and ground faults. This data also facilitates determination of the fault location and cause of relay operation. The measurements of active and reactive power provide data on the overall generating facility's response to the system disturbance.

In some cases, the dynamic reactive device is used within the ~~inverter-based resource~~Inverter-Based Resource and often connected to medium voltage collector bus. Regardless of where dynamic reactive device is connected, the output of it during system disturbances is important to understand overall performance of the plant during a disturbance. The measured or determined electrical quantities for dynamic reactive device are same as those specified to be measured/determined from high-side of main power transformer.

Recording of Electrical Quantities

For effective fault analysis, it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation. FR also shows generator output response to a system disturbance.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120 degrees, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current Ir, is calculated as a sum of vectors of three phase currents:

$$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable Elements as outlined in Requirement R2.

Rationale for Requirement R3

Time stamped pre- and post-trigger FR data aid in the analysis of power system operations and determination if operations were as intended.

The “Odessa Disturbance” report from September 2021 recommended high resolution oscillography data at the point of interconnection. The minimum recording rate of 64 samples per cycle is specified recognizing state-of-the-art for DME including storage any storage capability limitations and provides sufficient data to recreate accurate response of the ~~inverter-based resource~~Inverter-Based Resource to system disturbances.

Pre- and post-trigger fault data along with the SER data, all time stamped to a common clock, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Additionally, ~~inverter-based resource~~Inverter-Based Resources employ fast acting control systems (with built in protection functions) dictating ~~inverter-based resource~~Inverter-Based Resource's response to system disturbance. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles. To capture the full response of ~~inverter-based resource~~Inverter-Based Resource spread over a large geographic area, a 2 second total minimum record length synchronized to a common clock is necessary for FR data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data but are not capable of providing fault data in a single record with 120 continuous cycles total.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R3, Part 3.1.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R3, sub-Part 3.1.3.2 specifies a phase overvoltage or undervoltage trigger during voltage ride-through events.

The triggers specified in Requirement R3, Part 3.3 for dynamic reactive device FR data are similar to ones specified in Requirement R3, Part 3.1 for plant level FR data measured or determined on high-side of the main power transformer.

Rationale for Requirement R4

Large scale system disturbances generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and ~~inverter-based resource~~Inverter-Based Resource's response to large scale system disturbances. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event. The state-of-the-art DDR equipment is capable of continuous recording.

DDR data contains the dynamic response of the ~~inverter-based resource~~Inverter-Based Resource to a system disturbance and is used for analyzing complex power system events. This recording is typically used to capture short-term and long-term disturbances. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

DDR is used to measure transient response to system disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage and current from the same phase or positive sequence for each applicable main power transformer for analysis. It is also sufficient to provide a single frequency for any of the provided voltages since all main power transformers within an ~~inverter-based resource~~Inverter-Based Resource are at the same frequency. Recording of all three phases of voltage/current is not required, although this may be used to compute and record the positive sequence value(s). The electrical quantities for Real Power and Reactive Power on a three-phase basis can be measured/recorded or determined (calculated, derived, etc.).

The data requirements for PRC-028-1 are based on a system configuration assuming all normally closed circuit breakers on a BES bus are closed.

A crucial part of disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary to have DDR on high-side of the main power transformer(s) measuring the specified electrical quantities to adequately capture ~~inverter-based resource~~Inverter-Based Resource's response.

The Requirement R4, Part 4.1 requires either one phase-to-neutral or positive sequence voltage. However, the phase-to-phase voltage recording is acceptable. Since the BES operates under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Rationale for Requirement R5

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltages and frequency. The input sampling rate specified is same as one specified in the Reliability Standard PRC-002.

An output recording rate of electrical quantities of at least 60 times per second refers to the recording rate of the device. Recorded measurements of at least 60 times per second provide adequate recording speed to monitor the ~~inverter-based resource~~Inverter-Based Resource's response during power system disturbances. Since control system associated with ~~inverter-based resource~~Inverter-Based Resources is fast acting, higher frequency recording is necessary to accurately reconstruct events. An output recording rate of 60 times per second provides this higher frequency recording while not greatly increasing data storage requirements.

Rationale for Requirement R6

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 1 millisecond accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 1 millisecond accuracy will suffice with respect to providing time synchronized data. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. Note that the recently published IEEE Std 2800 requires the DME recording plant level data be synchronized to the clock with accuracy of ± 1 microsecond accuracy;

however, the accuracy requirement is set to ± 1 millisecond to strike a balance between need of accuracy and practical limitations of equipment necessary to achieve the stated accuracy. Recognizing challenges with distributing synchronizing clock signal to all IBR units with the Inverter-Based Resource, the IBR units (for capturing of SER data) are required to have synchronized device clock accuracy within ± 100 milliseconds of UTC.

The ~~inverter-based resource~~Inverter-Based Resources, which are not affected by inertial time constants, make changes in power production very rapidly. To understand and analyze control decisions during system disturbances and the reasons behind them over dozens of plants requires a high level of accurate time synchronization. The f~~F~~ollowing provide some examples of ~~inverter-based resource~~Inverter-Based Resource's fast response:

- Typical 90% response to a three-phase fault is < 40 ms.
- Central power plant controllers issue updated commands in as little as 40 ms upon detection of change in system conditions.
- Standard closed loop voltage control response can be <200 ms.
- Instantaneous Inverter protective trip decisions such as AC or DC overvoltage or reverse DC current can be made in less than 10 ms.

Rationale for Requirement R7

Requirement R7, Part 7.1 specifies a minimum time period of 20 calendar days inclusive of the day the data was recorded for which the data is to be retrievable. Data hold requests are usually initiated the same or next day following a major event, however, it takes a longer time to determine which data from which generating facility needs to be retrieved for event analysis. A 20 calendar day time period provides enough time for communication between various Entities regarding the event and need for data retrieval from DME at various generating facilities. The requestor of data has to be aware of 20 calendar day retrievability limit to ensure timely data hold requests. Requiring data retention for a longer period of time is expensive and unnecessary.

With the state-of-the-art equipment, having the data retrievable for the 20 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 20 days. To clarify the 20 calendar day time frame, let's assume that event occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 20 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 21, that is outside the 20 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER, FR and DDR data for generating facilities as per the applicability. To facilitate the analysis of system disturbances, it is important that the data is provided to the requestor within a reasonable time. Providing the data within 15 calendar days (or the granted extension time), subject to Requirement R7, Part 7.2, allows for reasonable time to collect the data and perform any necessary computations or formatting. An entity may request an extension of the 15 calendar days submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Disturbance analysis includes reviewing data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improve~~s~~ timely analysis. The formatting and naming convention requirements for SER, FR, and DDR are consistent with same requirements in the Reliability Standard PRC-002.

<u>SER data:</u> Requirement R7, Part 7.3 specifies a simple ASCII Comma Separated Value (CSV) format according to Attachment 1. It is necessary to establish a standard format as it allows data submitted by one entity or facility to be incorporated with same data provided by other entities or facilities to develop a detailed sequence of events timeline of a power system disturbance.

<u>FR data:</u> Requirement R7, Part 7.4 specifies <u>either CSV format with appropriate headers or </u>the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the FR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources.

<u>DDR data:</u> Requirement R7, Part 7.5 specifies either CSV format with appropriate headers or the IEEE C37.111 Standard for Common Format for Transient Data Exchange (COMTRADE) format for the DDR data. The IEEE C37.111 is well established in the industry. Exchanging data in a standard format helps in analysis of a power system disturbance, especially considering multiple data submission from many sources.

The 2013 revision of the IEEE C37.111 includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R7, Part 7.6 specifies the IEEE C37.232 Standard for Common Format for Naming Time Sequence Data Files (COMNAME) format for naming the SER, FR<u>,</u> and DDR data files. The lack of a common naming practice seriously hinders the event analysis and investigation process.

Rationale for Requirement R8

The standard requires that Entity restore the recording capability for SER, FR, or DDR data within 90 calendar days of the discovery of a failure. The 90 calendar day time period permitted in this requirement strikes a balance between reasonable time needed to restore capability while ensuring that recording capability is not out of service for an extended duration. If the recording capability cannot be restored within 90 calendar days due to limitations such as budget cycle, service crews, vendors, needed outages, etc., the entity is required to submit a Corrective Action Plan for restoring the recording capability to the Regional Entity and implement it. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored Element does not constitute a failure of the disturbance monitoring capability.

Considerations of FERC Order 901 Directives

Directive Language	Consideration of Directives
P 85: "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal to direct NERC to include in the new or modified Reliability Standards technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment. We agree with NERC that updating Reliability Standard PRC-002-2 to apply to registered IBRs for disturbance monitoring data collection, including recording sequence of events, digital faults, synchronized phasor measurements, inverter oscillography, inverter and plant-level fault codes, and data retention, could be one way to accomplish this directive. We further agree with the findings in NERC reports (e.g., a lack of high-speed data captured at the IBR or plant-level controller and low-resolution time stamping of inverter sequence of event recorder information has hindered event analysis) and direct NERC through its standard development process to address these findings."	The directive is addressed by new Reliability Standard PRC-028-1 which applies to • BES IBRs – Inclusion I4 of BES definition • Non-BES IBRs - Either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. The drafting team determined that introducing inverter-based resource monitoring requirements to Reliability Standard PRC-002 may create unintended consequences to purpose of Reliability Standard PRC-002 and may lead to industry confusion. Hence, a new Reliability Standard PRC-028-1 for monitoring requirements for Inverter-Based Resources is created instead of revising the Reliability Standard PRC-002. The Reliability Standard PRC-028-1, Requirements R1 through R6 obligates Transmission Owner and Generator Owner of Inverter-Based Resources to install Disturbance Monitoring Equipment to record sequence of event recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) data at various places within the Inverter-Based Resource. The Reliability Standard PRC-028-1, Requirement R7 obligates Transmission Owner and Generator Owner of Inverter-Based Resources to share recorded data with Transmission Planner, Planning Coordinator, Transmission Operator, Balancing

	Authority, Reliability Coordinator, Regional Entity, or NERC upon request.
P 86: "As a general matter, we agree with ACP/SEIA regarding the need to balance the burden to generator owners of collecting and providing data collected by disturbance monitoring equipment with the benefit of that data to reliability. Thus, in developing the directed data collection requirements, we direct NERC to consider the burdens of generators collecting and providing data, while assuring that Bulk-Power System operators and planners have the data they need for accurate disturbance monitoring and analysis. Likewise, regarding CAISO's request that the Commission direct NERC to consider requiring registered IBRs to provide additional data, we agree that such data collections may be warranted, and direct NERC to consider through its standards development process whether additional IBR data points (e.g., telemetry collections or other automated platform integrations) are needed to further enhance real-time visibility of Bulk-Power System operations."	The directive is addressed in the Reliability Standard PRC-028-1 which strikes a balance between recommendations from various NERC disturbance reports, comments received from industry including two inverter OEMs, available data recording technology, cost burden, reliability need, as well as use of collected data to aid with event analysis, model validation etc.
Paragraph 226: Although we are not directing NERC to include implementation dates in its informational filing and are leaving determination of the proposed effective dates to the standards development process, we are concerned that the lack of a time limit for implementation could allow identified issues to remain unresolved for a significant and indefinite period. Therefore, we emphasize that industry has been aware of and alerted to the need to address the impacts of IBRs on the Bulk-Power System since at least 2016. The number of events, NERC Alerts, reports, whitepapers, guidelines, and ongoing standards projects more than demonstrate the need for the expeditious implementation of new or modified Reliability Standards addressing IBR data sharing, data and model validation, planning and operational studies, and performance requirements. Thus, in that light, the	The implementation plan addresses Reliability Standard PRC-028-1 becoming effective on the first day of first calendar quarter from the effective date of Commission order approving the PRC-028-1. In addition, a phased-in approach is provided for Inverter-Based Resources that are in commercial operation before the effective date of this standard, with all Inverter-Based Resources in commercial operation before the effective date of this standard are required to fully comply with Requirements R1 through R7 by January 1, 2030. Recognizing circumstances beyond Entity's control (e.g., supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduling outages) which may

Commission will consider the justness and reasonableness of each new or modified Reliability Standard's implementation plan when it is submitted for Commission approval. Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date.	prevent the installation of Disturbance Monitoring Equipment per the time allowed at Inverter-Based Resources that are in commercial operation before the effective date of PRC-028-1, the implementation plan includes a process for requesting an extension from compliance dates. Inverter-Based Resources entering commercial operation after the effective date of PRC-028-1, Entities are required to comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or commercial operation date, whichever is later. For more details, see the PRC-028-1 Implementation Plan.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

UPDATED

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Open through August 12, 2024

Now Available

A formal comment period for **PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-based Resources** is open through **8 p.m. Eastern, Monday, August 12, 2024**. The drafting team decided to remove "**4.1.1. Transmission Owner that owns equipment as identified in section 4.2**" from the **Applicability** and all of the Transmission Owner referenced in the Requirements of Standard PRC-028-1.

This will be the last opportunity for NERC to ballot these projects through traditional mechanisms. The Board may take requisite action during the August 2024 Board of Trustees meeting to ensure directives are met.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

To assist industry in this upcoming comment and ballot period, NERC has released a Milestone 2 Summary that provides high-level overview of the current state of the associated projects and their interrelationships. The drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Note: PRC-002-5 passed the recent additional ballot (conducted June 5-15, 2024). The drafting team will be moving this standard to a final ballot when the PRC-028-1 ballots open (August 2-12, 2024) as only non-substantive revision(s) were made.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact **ballotadmin@nerc.net** to assist with the removal of any duplicate registrations.

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

Additional ballots for the standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 2 – 12, 2024**.

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 2021-04 Modifications to PRC-002 observer list” 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

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II
PRC-028-1

Formal Comment Period Open through August 12, 2024

Now Available

A formal comment period for **PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources** is open through **8 p.m. Eastern, Monday, August 12, 2024**.

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Comment Report

Project Name:	2021-04 Modifications to PRC-002 – Phase II | PRC-028-1
Comment Period Start Date:	7/22/2024
Comment Period End Date:	8/12/2024
Associated Ballots:	2021-04 Modifications to PRC-002 – Phase II Implementation Plan AB 4 OT 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 AB 4 ST

There were 60 sets of responses, including comments from approximately 135 different people from approximately 91 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the modifications made in PRC-028-1?

2. Do you agree with the Implementation Plan for revised PRC-028-1?

3. Do you agree the modifications made in PRC-028-1 are cost effective at unit level cost versus plant level cost compared to the benefit to reliability?

4. 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
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,NPCC,RF,SERC,SPP RE,Texas RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Matt Goldberg	ISO New England	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Elizabeth Davis	PJM	2	RF
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
					Scott Brame	North Carolina Electric	3,4,5	SERC

						Membership Corporation		
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
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
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
					Tyler Brun	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
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC

					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	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
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
David Kiguel	Independent	7	NPCC
Joel Charlebois	AESI	7	NPCC
Joshua London	Eversource Energy	1	NPCC
Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
Joel Charlebois	AESI	7	NPCC
John Hastings	National Grid	1	NPCC
Erin Wilson	NB Power	1	NPCC
James Grant	NYISO	2	NPCC
Michael Couchesne	ISO-NE	2	NPCC
Kurtis Chong	IESO	2	NPCC

					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the modifications made in PRC-028-1?	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While requiring recording all the fault codes and fault alarms as listed in R1.2 and R1.3 is certainly well-meaning, there may be disadvantages in requiring this breadth of data capturing and provision. Functional Entities (such as Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, and the Regional Entity) may not all equally benefit from receiving every fault code and fault alarm specified in R1.2 and R1.3. Fault codes and fault alarms differ across manufacturers and devices, and this is further complicated by the lack of standardization and consistent nomenclature in this area. Also, some entities may not be able to fully understand or draw proper conclusions from some of this data, which could lead to inconsistent and undesirable interpretation and application. Rather than requiring “all” the fault codes and alarms available, might it be worth considering for the standard to specify exactly which fault codes and alarms that the SDT believes would be beneficial?

AEP strongly recommends that the STD remove the requirement to capture all fault codes and alarms on IBR Units as SER data to +/- 100 millisecond from the standard and allow the GO to address IBR Unit performance issues as required under PRC-030.

PRC-029 requires the GO to ensure the design of IBR units meets the voltage and frequency ride through requirements or notify the applicable RC, BA and TO if the IBR is technically unable to meet those requirements. PRC-030 requires the GO to develop and execute a process to analyze Real Power change events including ride-through performance and implement corrective actions to address performance issues including applicable other GO IBR facilities.

Adding the requirement to capture all fault codes and alarms on IBR Units as SER data to +/- 100 millisecond back into this standard is unreasonable as it adds significant costs to the SER system and excessive administrative burden on the GO if an event occurs. Note that large IBR facilities have hundreds of IBR Units which would require the SER system to have thousands of SER data points. Is the intent of this requirement to have the TP, PC, TO, BA, RC, Regional Entity, or NERC determine the root cause of IBR Unit performance? If so, then why, as PRC-030 clearly holds the GO responsible for performing this analysis.

When an event occurs, the GO may be requested to submit DME data as proposed in PRC-028 while also having to address performance issues as required by PRC-030. Collecting SER data from every IBR Unit will be time consuming or require an expensive automated SER data collection system. The DME data for the MPT and collector bus should allow the TP, PC, TO, BA, RC, Regional Entity, or NERC to determine performance issues down to the IBR facility level and any corrective actions required on IBR Units would be address by the GO as required by PRC-030.

AEP disagrees with the mid-ballot period removal of Transmission Owner from the list of Functional Entities. The TO may in some cases be the owner of the MPT and high side breakers.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No

Document Name	

Comment

A) Duke Energy agrees with and supports the following NAGF comment:

1.b. Requirement R1.1:

i. NAGF members are still not certain that use of the term “collector bus(es)” includes feeder breakers and therefore are requesting that the requirement narrative be clarified to address this issue.

B) R1 Sections 1.2 & 1.3, 1.2.3 and 1.2.4, 1.3.3 & 1.3.4 require a mode status; this request is not a function of the recorders. In the technical rationale, please address this requirement or change standard to record voltage and frequency values instead of mode.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

1. Based on the latest draft, the Standards Drafting Team (SDT) has removed the Transmission Owner from this Reliability Standard’s applicability. Part 1.1 of Requirement R1 states a Generator Owner is required to retain sequence of event recording (SER) data for the circuit breaker positions associated with main power transformers, collector buses, shunt static and dynamic reactive devices, and AC-DC and DC-AC converters, if any, in case of VSC HVDC systems. Following the removal of the Transmission Owner, we believe the inclusion of circuit breaker positions for AC-DC and DC-AC converters is now misplaced and should also be removed.
2. Requirement R1 will require a Generator Owner to retain SER data. When applied to Parts 1.2 and 1.3, a Generator Owner is then required to perform a second action, which is to retain data for each individual IBR unit. The concept of the individual IBR unit was recently abandoned by the SDT in the previously proposed draft. We believe this is a reversal in the direction for Generator Owners to adopt this Reliability Standard. Nonetheless, we propose removing the phrases “shall be recorded” and “all” in these parts for clarity. We instead recommend rephrasing these parts to “…the following recorded data when triggered by ride-through operation or tripping of an IBR unit: fault codes, fault alarms, high and low voltage ride-through mode statuses, and high and low frequency ride-through mode statuses.”
3. Part 1.3 allows for an exclusion to Generator Owners if the IBR Facility is incapable to record sequence of event data for each individual IBR unit. We believe the measure for this requirement should be expanded so Generator Owners can document this incapability as evidence.
4. Based on the latest draft, the SDT expanded the requirements of a Generator Owner to retain fault recording (FR) data for each collector feeder breaker. While data may exist, the purpose of the Protection Systems associated with each feeder breaker is to protect the collector bus from a Fault and the possibility of a failure within the feeder breaker. These Protection Systems use existing voltage and current sensing devices already on-site as Protection System Components. However, the SDT also proposes triggering the recording of FR data on each collector feeder breaker based on overfrequency and underfrequency events. The SDT assumes existing Protection Systems are capable of being reprogrammed to include this functionality. However, some microprocessor relays associated with each collector feeder breaker may not have such functionality available.
5. Part 3.2.3 identifies settings when fault recording devices are triggered to begin recording data. We believe each of the individual triggers currently listed should also have a statement identifying only if such capabilities exist. A similar statement should also be added to the measure for this requirement to support this as evidence.
6. Requirement R6 will require a Generator Owner to retain time synchronized data within a device clock accuracy of ± 1 milliseconds of Coordinated Universal Time (UTC). In this recently proposed draft, the SDT has added a requirement that each IBR unit’s device clock

accuracy must have its accuracy within ± 100 milliseconds of UTC. This new requirement was embedded within Part 6.2 as a separate sentence and suggests each IBR unit must be synchronized to a clock source. For existing facilities, this capability may not be possible. We further believe this approach opens a gap and data associated with IBR units would then be required to have a device clock accuracy of ± 1 milliseconds of UTC. We propose the following approach to revising this requirement. First, remove the phrase “all” in reference to SER, FR, and dynamic disturbance recording (DDR) data in Requirement R6. Second, revise Part 6.2 to “Synchronized device clock accuracy within ± 100 milliseconds of UTC when applied on IBR unit recorded data or within ± 1 milliseconds of UTC.”

Likes 0	
Dislikes 0	

Response

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	No
Document Name	

Comment

TransAlta supports the comment provided by AEP regarding the recording of all the fault codes and fault alarms as listed in R1.2 and R1.3.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The *NAGF provides the following comments for consideration:*

a. Applicability Section 4.2.2 – recommend that the term “Non-BES Inverter-Based Resources” be revised to “Non-BES Inverter-Based Resource(s)” to be consistent with other IBR standards.

b. Requirement R1.1:

i. NAGF members are still not certain that use of the term “collector bus(es)” includes feeder breakers and therefore are requesting that the requirement narrative be clarified to address this issue.

c. Requirement 3.2.1 – NAGF members have noted that existing IBR facilities do not have the capability to provide a fault recording data record length of 2 seconds as defined in this requirement.

d. *Requirement 6.2 – NAGF members have indicated that individual IBR units do not have the ability to meet the +- 100 millisecond accuracy threshold.*

Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

This latest revision re-introduced the non-BES IBRs and FR per collector feeder which were removed from the previous version. The implementation costs for PRC-028-1 are still appreciably higher than PRC-002.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	

Capital Power supports the NAGF's comments:

The NAGF provides the following comments for consideration:

a. Applicability Section 4.2.2 – recommend that the term “Non-BES Inverter-Based Resources” be revised to “Non-BES Inverter-Based Resource(s)” to be consistent with other IBR standards.

b. Requirement R1.1:

i. NAGF members are still not certain that use of the term “collector bus(es)” includes feeder breakers and therefore are requesting that the requirement narrative be clarified to address this issue.

c. Requirement 3.2.1 – NAGF members have noted that existing IBR facilities do not have the capability to provide a fault recording data record length of 2 seconds as defined in this requirement.

d. Requirement 6.2 – NAGF members have indicated that individual IBR units do not have the ability to meet the +- 100 millisecond accuracy threshold.

Likes 0	
Dislikes 0	

Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

R1.

For IBRs – the OEMs are responsible for **SER** data only. The question OEMs have been having is "*what is a ride through operation*", to define what triggers capturing a ride through event. Its an ambiguous term where p.u. parameters and time duration need to be explicitly defined to be set at the IBR.

{C}1.1   there is no clarity on data that needs to be collected. Do we collect all listed or a single source? This should be stated within the requirement.

Recommendation to remove 1.3 since the requirements are the same as 1.2 except for the timing of COD with respect to when the Standard becomes effective. Requirement 1.3 appears to be reactive in nature. This timing may be better addressed as part of the implementation plan.

R2

The standard does not provide clarity on if collector feeder data is needed from all units or specific units. It is important to note that information is only available on the high side, nothing on the low side.

Recommendation to remove footnote 3 as IBR unit is not a defined term found in the NERC Glossary of Terms.

R3

For DFRs in the substation – there was a change adding MV "collector breakers" to record fault reporting data. No project today or E&C best practices recommend 34.5KV fault reporting with 64 samples/cycle.

Need clarification on whether data should be only for high side, whether for anything that tripped, or for the entire event. Our recommendation would be to focus on the high side of GSU only.

R6

IBRs must be time synchronized to +/- 100milliseconds which implies PTP or installing a GPS clock at each inverter.

Recommend Footnote 4 revised to "interchange" not "exchange."

Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No

Document Name	
Comment	

This latest revision re-introduced the non-BES IBRs and FR per collector feeder which were removed from the previous version. The implementation costs for PRC-028-1 are still appreciably higher than PRC-002.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

R1.3:

This requirement must be more specific with use of word “if capable”. Consider providing a clear exemption.

R2.1.3, R2.2.3, and R3.2.3

The protective devices with FR capabilities cannot capture Real and Reactive quantities. These quantities are typically calculated by using captured voltage and current quantities. SDT should clarify and state if calculated P and Q values are acceptable. If calculated P & Q values are not acceptable, then this requirement will have to be satisfied by installing dedicated fault recorders which can be a substantial burden on cost and implementation plan.

R3:

While WEC Energy Group fully supports triggering FR at proposed locations, WEC has a concern with 2 seconds recording requirement and 64 samples per cycle recording rate.

Most of the older microprocessor based protective relays do not have 2 seconds recording capabilities. The DT recognized this as well in the Technical Rationale document *(“Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data but are not capable of providing fault data in a single record with 120 continuous cycles total.”*). Note that microprocessor relays cannot record back to back events if the trigger is not active. This requirement, as currently written, will trigger costly upgrades. WEC suggest that SDT evaluates protective devices capabilities for most common relay manufacturers and reduces the recording requirement to 1 second.

Most of the older microprocessor based protective relays only have 4 or 8 samples/cycle sampling rate and do not have 64 samples per cycle recording rate capabilities. This requirement, as currently written, will trigger costly upgrades. WEC suggest that SDT evaluates protective devices capabilities for most common relay manufacturers and reduces the sampling rate below 64 samples per cycle.

These requirements seem to be more restrictive than PRC-002.

If recording and sampling requirement cannot be reduced, then existing FR equipment in commercial operation before the effective date of this standard should be exempted from 2 second recording requirement and 64 samples per cycle recording rate.

R3.1.3, R3.2.3, and R3.3.3:

SDT should determine pickups for the triggers. As currently written, entity could set pickups way too high or low and FR could never get recorded. For example, we can set 65Hz pickup for over-frequency. By the time we reach 65Hz, the event could be over.

R.6.2:

WEC Energy Group recommends that synchronized clock accuracy match PRC-002, which is +/- 2 milliseconds. An exception should be granted to IBR units in commercial operation before the effective date of this standard if synchronized signal at the IBR is not available or its accuracy cannot meet 100ms requirements.

R7:

WEC Energy Group suggests that R7 requirements match PRC-002 requirements.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

NIPSCO recommends that the STD remove the requirements R1.2 and R1.3, to capture all fault codes and alarms on IBR Units as SER and allow the GO to address IBR Unit performance issues as required under PRC-030.

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - 1,3,5 - WECC

Answer	No
Document Name	

Comment	
Please consider the following: Define the term IBR Unit - rather than in footnotes Following the removal of the Transmission Owner, we believe the inclusion of circuit breaker positions for AC-DC and DC-AC converters is now misplaced and should also be removed. Clarifying the term “collector bus(es)” to include feeder breakers. Many IBR units do not have the ability to meet the +- 100 millisecond accuracy threshold, considerably higher than PRC-002.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
R1.2 and R1.3 can involve hundreds of data points for a large facility if “all fault” and “all alarm” codes are included for every IBR unit on a site. Southern Company requests the SDT to consider adding verbiage to limit monitoring requirements to a sample of the IBR units within a facility. What (who) determines criteria of “if capable” in R1.3? Southern Company requests the SDT to consider updating M1 to include documentation explaining the IBR unit is not capable of providing the data for recording. Industry may require clarification of the term “ride through mode status” in R1.2 and R1.3. Southern Company requests the SDT to consider providing the necessary clarification. Southern Company believes R7.2 needs to be changed back to 30 days.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	No
Document Name	

Comment	
In response to many industry comments regarding the burdens and equipment limitations involved with previously proposed IBR Unit level monitoring requirements, the SDT responded in the Consideration of Comments issued on May 31, 2024, stating, "the SDT has reviewed the NERC disturbance reports, consulted with manufacturers, and considered the burden to industry. The data requirements are addressed in the PRC-028 Technical Rationale. All individual unit requirements have been removed from the latest draft, and meeting these requirements should be less of an issue with equipment used to monitor at the plant level." In Draft 4, not only have the IBR Unit level monitoring requirements been reinserted, but they have also been expanded to include monitoring at every IBR Unit. This sudden reversal of course runs counter to the previous three rounds of industry comment, and the SDT's own responses to those comments. Can the SDT provide additional justification or comment on the reasoning behind this change of course?	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
In response to many industry comments regarding the burdens and equipment limitations involved with previously proposed IBR Unit level monitoring requirements, the SDT responded in the Consideration of Comments issued on May 31, 2024, stating, "the SDT has reviewed the NERC disturbance reports, consulted with manufacturers, and considered the burden to industry. The data requirements are addressed in the PRC-028 Technical Rationale. All individual unit requirements have been removed from the latest draft, and meeting these requirements should be less of an issue with equipment used to monitor at the plant level." In Draft 4, not only have the IBR Unit level monitoring requirements been reinserted, but they have also been expanded to include monitoring at every IBR Unit. This sudden reversal of course runs counter to the previous three rounds of industry comment, and the SDT's own responses to those comments. Can the SDT provide additional justification or comment on the reasoning behind this change of course?	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	No
Document Name	
Comment	

In its June 14 comments, the ISO/RTO Council (IRC) Standards Review Committee (SRC) requested that inverter-level requirements be reinstated in PRC-028 and applied to all future IBR installations, at a minimum. The SRC provided numerous reasons for why the removal of these requirements is problematic and could impact reliability. The SRC understands from the SDT's consideration of this comment that the IBR unit SER data requirement was a compromise in lieu of the FR data. However, the SRC is still concerned that the FR data is limited to what the SER would provide as recommended in NERC's September 2019 guideline.

The SRC has noted since the initial draft that the DDR installation requirements proposed in PRC-028 should be considered in meeting DDR coverage requirements of PRC-002. Even though the SDT cites an example where there is not any overlap of DDR coverage between the 2 standards, the SRC believes the standard needs to allow for considerations of system topography in certain areas today where there is significant IBR penetration and possible DDR coverage overlap. The SRC believes the 2 standards need to be able to reconcile the possibility of overlapping coverage Footnote, ISO NE does not support this portion of the response to Q1.

Parts 2.2 and 3.2 are new and require a GO to have FR data for Collector Feeder breakers. Without a clear definition of "Collector Feeder" it is unclear whether this will be applicable only to generators that are configured to directly energize a Collector Feeder as part of a distribution network or whether R3.2 would include any non-BES distribution facilities (such as those located within a plant)?

The SRC also believes that Requirement R1, Parts 1.2 and 1.3 should also apply to broader impacts, including momentary cessation or any other abnormal behavior during events, and should therefore be revised to read as follows.

1.2. For IBR units in commercial operation after the effective date of this standard,

the following data shall be recorded when triggered by ride-through operation,

tripping, or longer-term disturbance response and recovery of an IBR unit including.

1.2.1. All fault codes.

1.2.2. All fault alarms.

1.2.3. High and low voltage ride-through mode status.

1.2.4. High and low frequency ride-through mode status.

1.2.5 Momentary cessation

1.2.6 Other abnormal behavior during events

1.3. For IBR units in commercial operation before the effective date of this standard,

the following data shall be recorded, if capable, when triggered by ride-through operation, tripping, or longer-term disturbance response and recovery of an IBR unit including.

1.3.1. All fault codes.

1.3.2. All fault alarms.

1.3.3. High and low voltage ride-through mode status.

1.3.4. High and low frequency ride-through mode status.

1.3.5 Momentary cessation

1.3.6 Other abnormal behavior during events

Because the “IBR Unit” definition will not be moving forward, it appears each standard seeking to acquire IBR unit information, such as Parts 1.2 and 1.3, will need to define what IBR unit means within the standard. In the case of PRC-028, the SRC understands that footnote 2 serves this purpose, and asks that the drafting team confirm whether the SRC’s understanding is correct.

The SRC supports Parts 2.2 and 3.2 primarily as a starting point for gathering collector feeder breaker FR data in this version of the standard. The SRC believes there is potential for future expansion of these requirements if they are found to be inadequate in the course of investigating the root causes of IBR performance issues.

Part 6.2 currently reads, “Synchronized device clock accuracy within ± 1 milliseconds of UTC. The IBR units shall have synchronized device clock accuracy within ± 100 milliseconds of UTC.”

The SRC seeks clarification from the SDT as to why 100 milliseconds was chosen for Part 6.2 when IEEE uses 100 microseconds. Currently, there are Generator Interconnection Agreements that require 1 millisecond time synchronization for plant- and unit-level device clock accuracy. Many entities are considering adopting the IEEE requirements, so an explanation for this difference is critical.

Additionally, the SRC recommends that PRC-028 be revised to require recording of inverter-level oscillography. As demonstrated throughout the 2022 Odessa Disturbance report, it is evident that inverter-level oscillography is readily available and critical to proper event analysis in cases where individual inverters trip offline even though frequency and voltage at the plant level remain in the must-ride-through zone. This is a known issue where terminal voltages and frequency measurements can vary greatly from the plant-level measurements due to the collector system and step-up transformer designs. In many cases this oscillography is available but just needs to be enabled and adequate storage made available. Table 19 in Section 11 of IEEE 2800 already requires recording of such information at the IBR unit level as well. Such a requirement could be applied to new units and to existing units that already have that capability available and simply need to enable it.

NERC recommended the following in the 2022 Odessa disturbance report for the SDT to consider (emphasis added).

“Monitoring Data ERCOT and the GOs in the Texas Interconnection ***have extensive data*** that is ***critical for root cause analysis***. This ***data includes*** plant-level high resolution oscillography data, plant SCADA data, and ***inverter-level*** sequence of events recording (e.g., fault codes) and ***oscillography data***. ***These types of measurements should be standard across industry for the purposes of event analysis and reducing the risk to plant performance***. The IRPS submitted a SAR, ***and Project 2021-04 is working on enhancements to PRC-002-2 to ensure this type of data is available at BES resources.”***

Footnote: MISO is a party to these comments but does not support the comments in response to Q1.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Jennifer Neville - Western Area Power Administration - 1,6

Answer	No
Document Name	

Comment

Support MRO NSRF comments

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	No
Document Name	

Comment

As written, Requirement R1 brings ambiguity with the use of “IBR unit” with the footnote definition. Additionally, what is a “ride-through operation”? For example- As written, the entity will need to record all aspect/Parts of R1.2 and R1.3 assuming the location failed the Ride-through definition or tripped offline. The discussion will be is it “all fault codes” of the inverter, converter, wind turbine generator, or high voltage direct current converter individually (as applicable)? Or something else? Requirement 1 Part 1.2 and Part 1.3 (including all sub Parts for both)- Capitalize “ride-through” as it is a defined term in another related Project.

Likes 0	
Dislikes 0	

Response

Kenisha Webber - Entergy - NA - Not Applicable - SERC

Answer	No
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Rob Robertson - Leeward Renewable Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy finds no objection to this standards’ proposed draft.	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
AES CE does not agree that SER data at every IBR Unit is necessary to meet the objectives of the Standard. Past revisions contained more reasonable solutions such as SER data at the end of each feeder. We believe this middle solution will have a significant positive impact on system reliability, while adding this data at every single IBR Unit offers only an incremental improvement in ability to analyze system disturbances at a huge burden to GOs.	
Likes 0	
Dislikes 0	
Response	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	
EEI supports the changes made to PRC-028-1 (Draft 4).	
Likes 0	
Dislikes 0	
Response	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"Please see EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	

Comment	
MISO supports the requirements (Parts 1.2 and 1.3) for IBR unit data. We also observe that, as the "IBR Unit" definition will not be moving forward, it appears each standard seeking to acquire IBR unit information, will need to define what IBR unit means within the standard. In the case of PRC-028, this is footnote 3. Is that correct? MISO supports Parts 2.2 and 3.2 as a starting point to gather collector feeder breaker FR data. That said, we also support the potential for future expansion of these requirements if they are found to be inadequate when investigating the root cause of IBR performance issues. **Part 6.2.** "Synchronized device clock accuracy within ± 1 milliseconds of UTC. The IBR units shall have synchronized device clock accuracy within ± ***100 milliseconds*** of UTC." Regarding Part 6.2., MISO is requesting clarification as to why the SDT chose 100 milliseconds when IEEE uses 100 microseconds. Currently, MISO's Generator Interconnection Agreement requires 1 millisecond time synchronization for plant and unit level device clock accuracy. As MISO is considering adopting the IEEE requirements, please explain the reason for the differential.	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
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	

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: 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

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Evergy - 1,3,5,6 - MRO

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5	
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	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,NPCC,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	
Document Name	

Comment

We do not disagree with modifications that have been made and we do not object to FERC order 901.

However, we do not believe this standard will improve reliability as the GO/GOP IBR entites would have to share data with (BAs, PAs, RCs, TOPs) only if they ask for said data. And those entities do not have any obligations to do anything with the data which GO/GOP IBRs would be required to provided them.

Consequently, we are unclear as to how GO/GOP IBRs that are required to procure and install a bunch of recording data and share recordings with entities, only if those entities ask for it, will do anything to improve reliability. As written this proposal looks like an expense to GO/GOPs with no reliability benefits.

All entities that GO/GOP IBRs are required to provide data to need to have requirements within this standard version detailing what they are to do with said data in order to improve reliability.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment

NRG Energy Inc is in support of the comments made by EPSA.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the Implementation Plan for revised PRC-028-1?

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	

PRC-029 and PRC-030 hinge on the Implementation Plan (IP) for PRC-028. The inconsistent approach (“design”/”operation” aspects of Requirements in PRC-029/030 IPs) and use of “commercial operations date” in PRC-028 IP does not provide clarity. The DTs did not define what the design and operation aspects of PRC-030 are so compliance monitoring will be difficult if at all achievable until ALL parts of PRC-028 are applicable (essentially 2030). The use of commercial operation date is inconsistent with reliability and differs across the United States. There are no compliance evaluations that can be done for non-BES IBRs until after Jan 1, 2030.

For the following Implementation Plan requirement, the DT needs to be extremely clear that the 15 calendar months is ONLY applicable to the “effective date of the standard” portion of the phrase and not the “commercial operation date”:

“For non-BES Inverter-Based Resources in commercial operation after May 2026: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later. “

Does the DT confirm that interpretation of the phrase is correct? Effective date of standard plus 15 calendar months OR commercial operation date whichever is later is the correct way to read that phrase.

Most implemtation plans are effective on the first day of a quarter. If May is actually the desired month, the IP should not simply say “May 2026” it should be specivic such as May 1, May 15, or May 31, 2026.

Having a process for extension of compliance embedded within an Implementation Plan is not conducive or supportive to reliability. As written, this will be an administrative effort with NO defined timeline in sight and no process to support it. The ERO Enterprise should utilize the current processes in place. That is, if the entity, who has had years to be ready, is noncompliant they self-report the issue and follow the mitigation process. Putting this process in place requires a second set of books for compliance determination and status. The Implementation Plan (and the dependence of other Implementation Plans) does not set any expectation for IBRs to be compliant by any set date and does not support FERC’s intention of having Standards applied to IBRs no later than 2030. What happens if the entity does not provide information or provides information that is found to be incorrect and the CEA does not approve the extension? What happens if the entity does not supply the extension request in less time than “required” (i.e., “no later than three months prior to the compliance date”)? FERC recently ruled on cold weather standards regarding Corrective Action Plans being too long. The timing for these exemptions is non-existent and provides a compliance loophole that can be easily exploited by entities not addressing reliability in an effective manner. Those entities invested in reliability should be working towards implementation of these Requirements now. Unfortunately, the system is experiencing entities that are more interested in the bottom line versus reliability. Implementation Plans are not enforceable but set dates for enforcement based on the Standard Requirement language. No extension process should be considered. The electrical ecosystem has been experiencing IBR issues for a decade already and the risk this technology has exposed can not continue by allowing extensions. This again begs for a timeline diagram for the implementation of these 3 Standards (PRC-028/029/030) so that everyone knows the exact expectations for compliance dates.

Likes 0	
Dislikes 0	
Response	

Jennifer Neville - Western Area Power Administration - 1,6

Answer	No
Document Name	
Comment	

Support MRO NSRF comments

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - 1,3,5 - WECC

Answer	No
Document Name	
Comment	

Please consider the following:

Clarification regarding the Compliance Enforcement Authority (CAE) process to be used for evaluating a PRC-028 compliance date extension request.

DME equipment installation time needs to be considered during implementation.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	
Comment	

NIPSCO agrees with the majority of the implementation plan but still has concerns with the “15 calendar months following the effective date of the standard” requirement for inverter-based resources entering commercial operation after the effective date, and believes that more time is needed to properly budget, modify designs and procure equipment for projects already under development. NIPSCO proposes modifying the following language: For inverter-based resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within “36 calendar months following the effective date of the standard or by" the commercial operation date, whichever is later.

Likes 0	
Dislikes 0	

Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
Unless WEC Energy Group comments listed in #1 above are addressed, the implementation plan will be too short.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Although the PRC-028 Implementation Plan mirrors PRC-002-2 Implementation Plan, PRC-028 requires all BES IBRs and many non-BES IBRs to have DME installed. If the GO has a large IBR fleet, numerous DME installations would be required with a demanding project schedule. With the large amount of DME required to be installed per PRC-028, OEMs might not be able to provide GOs with a timely supply of DME equipment. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	

Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	

Comment
For the implementation plan, we recommend focusing on those sites with a COD post the Standard becoming effective. Having an implementation for units with a COD prior to the Standard becoming effective does not appear consistent with implementation of other Standards, being retroactive, and will create undue burden to IBR owners who will need to perform rework on existing sites, as vendors have already indicated the equipment to meet compliance will not be available until 2026. In addition, we note the duration to implement has become an issue as the timeline has shifted by one year and the deadline to fully implement remains by 2030. NextEra recommends an implementation of 2032 to be fully compliant, providing reasonable time for the first 50% and the remainder of the sites. While we appreciate the Implementation Plan's note recognizing the potential supply chain issues and the potential for registered entities to address delays outside of their control, we do not think addressing these known issues as part of Compliance and Enforcement is the most effective for both industry and the ERO. As currently written, not only will we have further supply chain issues generated from the timeline reduction and the retroactive nature of requirement 1.3. but additional administrative burden post Standards development.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	

Comment
PRC-002 allowed ~6 years for implementation. It appears that PRC-028 will allow ~3.5 years for non-BES IBR owners to meet compliance following the registration deadline and ~4.5 years assuming an effective date of 7/1/25 for BES owners. If non-BES or BES owners have multiple existing facilities to update for compliance this may be difficult. Consider giving a similar time window of ~6 years to meet compliance. It seems larger facilities meeting this standard would be more beneficial than the numerous non-BES facilities.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Although the PRC-028 Implementation Plan mirrors PRC-002-2 Implementation Plan, PRC-028 requires all BES IBRs and many non-BES IBRs to have DME installed. If the GO has a large IBR fleet, numerous DME installations would be required with a demanding project schedule. With the large amount of DME required to be installed per PRC-028, OEMs might not be able to provide GOs with a timely supply of DME equipment.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	No
Document Name	

Comment

TransAlta supports the comments provided by Radian Generation regarding requesting an extension.

TransAlta supports the comments provided by Berkshire Hathaway regarding implementation timelines.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

1. We believe the Process for Requesting an Extension from Compliance Data has embedded inefficiencies that could place undue burdens on Generator Owners. As Generator Owners patiently await on an approval for an extension from their Compliance Enforcement Authority (CEA), even providing additional follow-up information requested from that CEA in a timely matter, the compliance burden still lies with the Generator Owner until such an extension is finally granted. Industry continues to see some CEAs struggle with addressing their backlogs for handling potential non-compliance of existing registered entities. Some of these registered entities have not even received a response from their CEA in years. We believe some accountable on the ERO Enterprise should be included within this Implementation Plan, whether under the Requesting an Extension Process or as a general consideration. This includes the development of a standard template that would be used across the ERO Enterprise for Generator Owners to complete when making an extension request. This template would identify all the information that is required to make the extension upfront. A completed template by the Generator Owners then would not impede the request because of

insufficient information. The process should also have some timeline constraints, such that a request is never left unanswered. This time could be reasonable to account for impacts on CEA resources, such as six months and at which time, the CEA is required to provide an update to the requesting Generator Owner on its review of the request. Failure to provide an update, or continuously extending this period for the CEA to process the request, would automatically imply the request for extension has been granted to the Generator Owner. NERC should also oversee the requesting process to ensure consistency is evenly applied by each CEA.	
Likes 0	
Dislikes 0	
Response	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	No
Document Name	
Comment	
PRC-002 allowed ~6 years for implementation. It appears that PRC-028 will allow ~3.5 years for non-BES IBR owners to meet compliance following the registration deadline and ~4.5 years assuming an effective date of 7/1/25 for BES owners. If non-BES or BES owners have multiple existing facilities to update for compliance this may be difficult. Consider giving a similar time window of ~6 years to meet compliance. It seems larger facilities meeting this standard would be more beneficial than the numerous non-BES facilities.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD agrees with the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	

Answer	No
Document Name	
Comment	

AEP supports the implementation schedule for R1-R7 for units in commercial operation prior to the effective date but requests the same implementation schedule be used for R8 as the DME system most likely will not have been installed by the effective date of R8. If the intent is to have a CAP to identify the targeted compliance date, this would create excessive administrative burden on the GO.

The example provided for compliance of IBR facilities entering commercial operation *after* the effective date does not make sense as stated. AEP recommends that the effective date for IBR facilities entering commercial operation after the effective date be required to comply with the standard within three (3) calendar years of the effective date of Reliability Standard PRC-028-1 to align with the requirements for existing IBR facilities.

For the reasons stated above, the compliance date for R8 for Non-BES IBR facilities should be the same as R1-R7.

Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	
Comment	

Tri-State agrees with the comments provided by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Rob Robertson - Leeward Renewable Energy - 5

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"Please see EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	

Comment	
Ameren agrees with and supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Please provide further clarification regarding the Compliance Enforcement Authority (CAE) process to be used for evaluating a PRC-028 compliance date extension request, including the proper mechanism for submitting a request and timelines involved in the evaluation process.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	

The NAGF requests further clarification regarding the Compliance Enforcement Authority (CAE) process to be used for evaluating a PRC-028 compliance date extension request.

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

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy finds no objection to this standards' proposed draft.

Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,NPCC,SERC,RF, Group Name ACES Collaborators	
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	
Rhonda Jones - Invenergy LLC - 5,6	
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	
Colin Chilcoat - Invenergy LLC - 5,6	
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	

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: 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	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
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	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4

Answer	
Document Name	

Comment
This implemention plan appears more reasonable then the PRC-29 and PRC-30's six month implementation plans. We believe the implementation plans for those two standards should be the same as PRC-28.

Likes 0	
Dislikes 0	

Response

3. Do you agree the modifications made in PRC-028-1 are cost effective at unit level cost versus plant level cost compared to the benefit to reliability?

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
The SDT has not provided any cost or expected reliability indices improvement estimates. Consequently, it is impossible for entities to determine if this proposal is cost effective, or not; or to what extent, this proposal will improve reliability. Reliability standards should not be added or changed until the SDT provides said information so that Registered Entities can make educated determinations related to the cost and benefits of reliability standard modifications or new proposals. Basically, what we are being asked to do is to analyze the cost and reliability benefits this proposal would provide without any data. And, ironically GO/GOP IBR Entities are being asked to spend money to procure and install a bunch of devices to record data and/or to perform new activities that may, or may not, improve reliability. And if they do improve reliability, we don't have any idea if the reliability benefits are worth the cost. Electricity customers Nationwide will have the rates raised and there is no justification or hard evidence related to the improved reliability increase magnitude; i.e. no cost/benefit justification to provide customers as to why then rates will be increased.	
Likes 1	Utility Services, Inc., 4, Powers Carver
Dislikes 0	
Response	

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
SMEs responded with the following comments: • "The modifications will create undue burden on the utilities for likely little improvement to reliability. The study of IBRs on the grid should have taken place before the unprecedented addition of these intermittent resources without enough data to judge the impact to reliability."	
Likes 0	
Dislikes 0	
Response	

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No

Document Name	
Comment	
"The modifications will create undue burden on the utilities for likely little improvement to reliability. The study of IBRs on the grid should have taken place before the unprecedented addition of these intermittent resources without enough data to judge the impact to reliability."	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State agrees with the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
As stated previously, adding the requirement to capture all fault codes and alarms on IBR Units as SER data to +/- 100 millisecond back into this standard is unreasonable, as it adds significant costs to the SER system and excessive administrative burden on the GO if an event occurs.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	

Answer	No
Document Name	
Comment	

This standard makes sense for new inverter-based resources (IBRs). However, for the legacy IBRs the reliability benefits do not justify the costs. The costs to design, purchase and install the required equipment for IBRs that are 10 years old or older, does not make sense if the facility has limited or no controls compared to the modern IBR equipment being installed today. PRC-028-1 provides a limited exemption in Requirement R1 for the data to be collected, but the data could be useless if the IBR's legacy controls place hard limitations on the ability of the IBR to actually ride-through a system disturbance.

Likes 0	
Dislikes 0	

Response

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	No
Document Name	
Comment	

PRC-028-1 will result in costs that are not in-line with the reliability benefits provided. These costs are not only for the design and implementation of the monitoring but also for new communications infrastructure for legacy locations or compliance related staff to monitor, track and maintain compliance where it was not required before. For those owners that stream PMU data this standard could add significant communications costs to upgrade older facilities. The reliability benefit of installing, maintaining, and operating monitoring capabilities on existing equipment does not justify the cost.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

1. We believe the recent modifications to reintroduce the individual IBR unit to the proposed NERC Reliability Standard provide very little benefit to reliability. The information available at the IBR collector bus level and main power transformers are more than sufficient to determine how a IBR facility performed following a Disturbance. We question how operational entities would incorporate fault code and fault alarm data into their post-event analyses for improving BPS reliability. Generator Operators and Generator Owners, who are more familiar with fault codes and fault alarms, use such data for troubleshooting a localized issue detected within the IBR facility and to generate more immediate corrective actions in response.

Likes 0	

Dislikes 0	

Response

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	No
Document Name	

Comment

TransAlta supports the comments provided by SMUD and BANC regarding legacy IBRs. Furthermore, TransAlta does not believe the standard adequately addresses paragraph 86 from FERC Order 901, "to consider the burdens of generators collecting and providing data, while assuring that Bulk-Power System operators and planners have the data they need for accurate disturbance monitoring and analysis."

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

AES CE believes this is not a cost effective approach to meet FERC Order 901. The requirement for SER data at every IBR Unit offers marginal benefit to reliability as compared to having SER data at the end of every feeder while incurring significant additional costs.

AES CE recommends that the SDT leverage the expertise of Project Finance SMEs at the entities to understand the feasibility of implementing this new Standard, and the potential impacts to reliability that these additional costs could incur.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Including non-BES IBRs for PRC-028-1 could present additional financial difficulties that might cause some GOs to consider other options. Due to the expenses of NERC Registry and PRC-028 requirements, non-BES IBR facilities could possibly be shut-down rather than meet the upcoming NERC requirements. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	

PRC-028-1 will result in costs that are not in-line with the reliability benefits provided. These costs are not only for the design and implementation of the monitoring but also for new communications infrastructure for legacy locations or compliance related staff to monitor, track and maintain compliance where it was not required before. For those owners that stream PMU data this standard could add significant communications costs to upgrade older facilities. The reliability benefit of installing, maintaining, and operating monitoring capabilities on existing equipment does not justify the cost. However, MRO NSRF does agree that the requiring monitoring capabilities on new equipment moving forward may be a cost-effective method to assist in addressing the issues set forth in the SAR and NERC Reports.	
Likes 0	
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Including non-BES IBRs for PRC-028-1 could present additional financial difficulties that might cause some GOs to consider other options. Due to the expenses of NERC Registry and PRC-028 requirements, non-BES IBR facilities could possibly be shut-down rather than meet the upcoming NERC requirements. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
Feeder requirements under 3.2 are not necessary on smaller NON- BES sites. Can this requirement be updated to be applicable to only larger BES PV sites only?	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group does not agree that these modifications are cost effective compared to the benefit to reliability. As currently written, the Standard will trigger costly upgrades, especially to wind IBRs which were not identified as troubled equipment during the past IBR disturbances. To make it more cost effective, exceptions must be provided for certain equipment already in service.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Adding the requirements to capture all fault codes and alarms on IBR Units as SER data is unreasonable, as it adds significant costs and excessive administrative burden on the GO if an event occurs.	
Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
There are concerns about cost effectiveness if the entity is required to purchase hardware in order to reach the level of data recording suggested. If the entity is only required to update software, then the suggested updates appear cost-effective. We recommend incorporating an exception process for smaller entities who do not have the ability to configure existing equipment to gather the requested level of data recording.	
Likes 0	
Dislikes 0	
Response	

Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	
The high cost of outfitting existing IBRs to comply outweighs the reliability gained.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company believes the modifications made to PRC-028-1 for legacy IBRs are **not** cost effective at unit level cost versus plant level cost compared to the benefit to reliability due to R1.3 inclusion.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
The reversal of course in Draft 4 to require IBR Unit level monitoring at every IBR Unit imposes significant costs on entities without a commensurate benefit to reliability.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
The reversal of course in Draft 4 to require IBR Unit level monitoring at every IBR Unit imposes significant costs on entities without a commensurate benefit to reliability.	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments:

ACES agrees with the approach taken by the SDT to create a new Standard to specifically address inverter-based resources; however, we disagree with making this new standard inclusive of all BES inverter-based resources regardless of risk to the BPS.

In the opinion of ACES, a blanket approach requiring every IBR to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which inverter-based resources pose the biggest risk to the BPS, and where disturbance monitoring and reporting would provide the most benefit to the BPS, before selectively adding such capabilities.

We believe that a risk-based approach is the best and only truly cost-effective option for all applicable IBRs, we believe that this is especially true for existing IBRs. In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach for IBRs as is done in PRC-002-5 for synchronous generating resources.

Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,NPCC,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	

ACES agrees with the approach taken by the SDT to create a new Standard to specifically address inverter-based resources; however, we disagree with making this new standard inclusive of all BES inverter-based resources **regardless of risk** to the BPS.

In the opinion of ACES, a blanket approach requiring every IBR to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which inverter-based resources pose the biggest risk to the BPS, and where disturbance monitoring and reporting would provide the most benefit to the BPS, before selectively adding such capabilities.

We believe that a risk-based approach is the best and only truly cost-effective option for all applicable IBRs, we believe that this is especially true for existing IBRs. In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach for IBRs as is done in PRC-002-5 for synchronous generating resources.

Likes 0	
Dislikes 0	

Response	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rob Robertson - Leeward Renewable Energy - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
At this time, FirstEnergy finds no issue with the cost effectiveness toward the scope of this standard	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

"Please see EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3

Answer	
Document Name	

Comment

Cannot comment on cost effectiveness

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

Black Hills Corporation will not comment on cost effectiveness.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Duke Energy will not submit a response to the cost effectiveness of the proposed changes.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: 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 does not have any comments as to the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	
Document Name	

Comment	
Ameren does not have any additional comments on the cost effectiveness of this project.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
No comment on the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	

4. Provide any additional comments for the standard drafting team to consider, if desired.

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Elevate appreciates the opportunity to comment on the draft NERC standards, particularly those pertaining to future IBR NERC Reliability Standards, and FERC Order No. 901 directives.

Elevate continues to strongly encourage NERC to reconsider adoption of IEEE 2800-2022. The unwillingness to adopt IEEE 2800-2022 by NERC is leading to entirely duplicative efforts that are not serving any additional value as compared to the work conducted in the IEEE 2800-2022 developments. It does not appear that a holistic approach and strategy is being taken to meet the FERC Order No. 901 directives, which is leading to very low ballot scores, significant rework, and misalignment with industry recommended practices.

Elevate strongly recommends a single NERC standard that adopts IEEE 2800-2022 in a uniform and consistent manner. NERC can also issue a reliability guideline or implementation guidance that supports industry implementation of the standard. Rather than recreate parts of IEEE 2800-2022 inconsistently over multiple different standards, Elevate recommends a singular standard for BPS-connected IBR capability and performance requirements related to IEEE 2800-2022. Additional NERC standards can be developed where needed in situations where they are not covered directly with IEEE 2800-2022 (e.g., NERC PRC-030).

While improvements have been made in this latest draft of the NERC PRC-028 standard, this standard is duplicative with IEEE 2800-2022 Clause 11 yet the latest draft of the standard is still missing some of the monitoring aspects covered in the IEEE 2800 standard, including power quality monitoring data and IBR unit FR/DDR data (and additional fault code types). The 2021 Odessa Disturbance report and the NERC IBR Reliability Guideline document both give a recommendation to include FR/DDR data on some IBR units on the collector busses at IBR plants, but currently the draft PRC-028 standard has no FR/DDR requirement for IBR units. This PRC-028-1 standard and other NERC IBR-focused standards should be conforming to/matching the IEEE 2800 standard.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	

PRC-028 R1 is using “IBR unit” versus IBR and provides a “definition” in the footnote 3 (only footnoted once but used several time in Requirement). Why complicate the issue with a definition in a footnote that would not be needed if using IBR only? That lacks consistency with PRC-029 and PRC-030 (which are inconsistent between each other as well). The use of commercial operation is ambiguous. Different entities may have a

different definition of "commercial operation." Suggest clarification of what commercial operation is. Suggest someting to the effect of IBRs must have these installed prior to first synch. Entities will have to maintain and provide ALL commercial operating dates for all IBRs. The VSLs as written will require an extent of condition (entity will have to supply ALL applicable "Elements" and /or electrical quantities to determine severity level if a single issue is found with a sample.)	
Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	
Document Name	
Comment	

Given the reliance on electronic communications for compliance such as the Secure Evidence Locker, the SRC notes that it seems inappropriate to allow for hard-copy documentation, e.g. M1:

The Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1

This also seems contradictory to the more specific data format requirements contained elsewhere in the standard, such as in Parts 7.3 and 7.4, and the SRC requests that the SDT consider revising M1.

7.3. SER data shall be provided in ASCII Comma Separated Value (CSV) format

following Attachment 1.

7.4 FR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted…

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1, Group Name Exelon

Answer	
Document Name	

Comment

Exelon agrees with the EEI, Footnote 2 should be deleted from the final draft.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,NPCC,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

ACES Member EKPC had the following additional comment:

"DDR data for all BES and NON-BES IBRs is a large burden. If the Standards Drafting Team finds it untenable to take a risk-based approach for all PRC-028-1 Requirements (similar to PRC-002-4), then we recommend that PRC-028-1 Requirement R4 and R5 have exclusive applicability based on a risk-based analysis performed by the Reliability Coordinator."

Thank you for the opportunity to comment.

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

Rhonda Jones - Invenergy LLC - 5,6

Answer	
Document Name	

Comment

R1.2.1, R1.2.2, R1.3.1, and **R1.3.2** are far too broad as currently drafted and must be amended to target specific categories of fault codes that the SDT deems relevant to the analysis of BES disturbances. Depending on the OEM, there may be thousands of fault codes, a vast majority of which would be entirely irrelevant to the purpose of analyzing BES disturbances.

R6.2 should be amended to include "if capable."

Invenergy thanks the drafting team for the opportunity to provide feedback.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	

Invenergy thanks the drafting team for the opportunity to provide feedback.

R1.2.1, R1.2.2, R1.3.1, and **R1.3.2** are far too broad as currently drafted and must be amended to target specific categories of fault codes that the SDT deems relevant to the analysis of BES disturbances. Depending on the OEM, there may be thousands of fault codes, a vast majority of which would be entirely irrelevant to the purpose of analyzing BES disturbances.

R6.2 should be amended to include "if capable."

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 RSC	
Answer	
Document Name	
Comment	

NPCC RSC supports the project.

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	

Southern Company does not agree with the language in PRC-028, R8 requiring a Corrective Action Plan to be submitted to the Regional Entity. If at any time a Regional Entity desires to review a TO's or GO's Corrective Action Plans, they have the authority to request them. Requiring the Corrective Action Plans to be submitted to the Regional Entity with no requirement for action by the Regional Entity is purely administrative and does nothing to improve the reliability of the Bulk Electric System. Further, the timely development and implementation of a Corrective Action Plan needed to repair equipment can be thoroughly examined during an audit engagement. This same reasoning applies to PRC-002, R12 and is also recommended to be removed.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	
Document Name	

Comment

1. Based on the purpose statement, this standard appears to be creating double jeopardy. If a non-compliance occurs with PRC-028, the entity is presumably non-compliant with Modeling standards in addition to PRC-029. However, it seems that the intent of the standard is similar to PRC-002: to capture adequate data to facilitate analysis of BES System Disturbances.

2. We recommend that the DT recreate the purpose statement of PRC-028 to align with the PRC-002 purpose statement. We believe the intent of the standard is to gather the necessary event data to analyze system disturbances. PRC-002 focuses on the TO (and some large generation facilities that meet the threshold in R5) gathering the appropriate data and doing it in a manner that is consistent so it can be analyzed in a more efficient manner when a large system disturbance occurs. PRC-028 suggests that IBR’s, regardless of size, have significant event recording capabilities. For the smaller IBR facilities that will inevitably be applicable to this standard, this data may not be useful at all. If this standard requires upgrades to hardware or additional hardware to meet the recording capabilities, this may not be commercially viable for these smaller entities that may not have any relevant data for analysis. Therefore, if care is not taken when further development of this standard occurs, the majority of these Requirements would end up being administrative in nature and not be beneficial for improved reliability of the BES.

3. In our entity’s review of this project, we are voting in the affirmative. We understand and appreciate that this project addresses important considerations for reliability and security responsiveness. However, we also recognize that this project in its current form presents compliance and

performance risks that remain unresolved. While affirmatively supporting this project to address the immediate regulatory assignments tied to FERC Order 901, NERC and the ERO must continue a constructive dialog with industry beyond this vote to truly optimize the impacts of this project on reliability, sustainability, and affordability. We encourage NERC to permit extending the SDT team and project to offer prospective enhancements or revisions to satisfy these compliance and performance risks.

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	
Document Name	

Comment

Ameren agrees with and supports EEI's comments.

Ameren offers the following for consideration:

R1: Ameren recommends that the drafting team clarify what is meant by "fault codes" and "fault alarms" as applied to the standard for R1.

R2: The standards drafting team requires real and reactive power expressed on a three-phase basis. However, during a fault, these values would be zero. Ameren recommends that Volts and Amps are the only necessary data collected during a fault event.

R3, Ameren proposes 30 to 60 cycles per event with 2 cycles of pre-event data at 32 samples per cycle, which can be accomplished with most modern relays. The values for output recording rate and synchronized device clock accuracy should match PRC-002. Additionally, the number of days in R7.1 and R7.2 should also match PRC-002.

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	EEI Near Final Draft Comments _ Project 2021-04 PRC-002_028 Draft 4 _ Rev 0a __ 8_06_2024 (002).docx

Comment

See comments submitted by the Edison Electric Institute in the attached file

Likes 0	
Dislikes 0	

Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI offers the following non-substantive change to PRC-028-1 for consideration: • Footnote 2 should be deleted. "IBR unit" is no longer used in the proposed definition of IBR and therefore has no meaning within the context of this Reliability Standard, negating the need for Footnote 2.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
The cost and burden of the proposed PRC-028 requirements are not believed justified by the reliability benefits it would provide. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	

Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO

Answer	
Document Name	

Comment

MRO NSRF is concerned about Regional Entities' ability to objectively and correctly evaluate requests for Seeking Extensions to Compliance Dates. MRO NSRF recommends that the SDT create clear and auditable criteria that if met, allow for the extension of compliance dates. GOs and TOs would submit notification to the Regional Entity that they will require an extension to the compliance dates, based on the met criteria. The Regional Entities' role would be to ensure that the proper criteria are indicated by the GO or TO to allow for an extension of compliance dates, rather than make subjective decisions on approval of requests. This would also eliminate concerns about differences between regions in allowing for extensions.

MRO NSRF does not agree with the language in R8 of PRC-028 and R12 of PRC-002, requiring a Corrective Action Plan to be submitted to the Regional Entity. If at any time a Regional Entity desires to review a TO's or GO's Corrective Action Plans, they have the authority to request them. Simply requiring the Corrective Action Plans to be submitted to the Regional Entity with no requirement for the Regional Entity to do something with them is purely and administrative and does nothing to improve the reliability of the Bulk Electric System.

While MRO NSRF supports much of this proposed standard, MRO NSRF does not agree with requiring the retrofitting of monitoring equipment on existing individual inverter based generating resources as included by I4, MRO NSRF does however believe that forward looking design standard addressing new installations would be reasonable.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

The cost and burden of the proposed PRC-028 requirements are not believed justified by the reliability benefits it would provide.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	
Document Name	
Comment	
TAL understands that the committee was following previous precedent of the 20MVA or greater facilities; however, we believe this standard will create undue hardship on utilities who will be required to meet this standard. 20MVA seems like a low threshold for the size of IBRs. TAL believes the impact of IBRs as small as 20 MVA seems minimal to the integrity of the BES.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
1. Many existing devices used for fault recording (SEL-351 for example) cannot meet the 2.0 second duration in R3.1.1. A duration of 1.0 second would better align with equipment capabilities. Perhaps the clause could be written that all new equipment should have the 2.0 second duration capability while existing equipment has requirements in-line with the capabilities of the equipment installed over the past few years.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	
Likes 0	
Dislikes 0	
Response	

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	
Document Name	
Comment	
-	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
1. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	

Document Name	

Comment

1. Purpose: we suggest harmonizing the usage of the term Inverter Based Resources and its acronym across the projects 2021-04, 202-02 and 2023-03. We suggest adding the acronym IBR in brackets after the capitalized term Inverter Based Resources, and to refer to IBR throughout the document.

2. We suggest that the drafting team modify section 4.2.2 to reflect the changes that were made to PRC-029-1 in Project 2020-02 and PRC-030-1 in project 2023-02. We suggest the following wording:

“The Elements associated with (1) Bulk Electric System (BES) IBRs and (2) Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.”

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	
Document Name	

Comment

The language in **Section 4, Applicability** does not match the language used in the latest proposed versions of PRC-029-1 and PRC-030-1.

The drafting team should remove the words “that owns equipment as identified in section 4.2” in Section 4.1.1. and ensure that the Section 4, Applicability language match the language in PRC-029-1 and PRC-030-1. The final, preferred language for Section 4, Applicability is shown below. This change is non-substantive and could be made in the final ballot.

The existing language in PRC-028-1 is as follows:

4.1. Functional Entities:

4.1.1. Generator Owner ***that owns equipment as identified in section 4.2***

4.2. Facilities:

4.2.1 BES Inverter-Based Resources

4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

SMUD's preferred language in PRC-028-1 Section 4, Applicability is as follows:

4.1 Functional Entities:

4.1.1. Generator Owner

4.2. Facilities:

4.2.1 BES Inverter-Based Resources

4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: 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

None are being provided.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Duke Energy agrees with and supports the following EEI comment:

EEI offers the following non-substantive change to PRC-028-1 for consideration:

• Footnote 2 should be deleted. "IBR unit" is no longer used in the proposed definition of IBR and therefore has no meaning within the context of this Reliability Standard, negating the need for Footnote 2.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	

Comment

AZPS supports the following comment submitted by EEI on behalf of its members:

Footnote 2 should be deleted. “IBR unit” is no longer used in the proposed definition of IBR and therefore has no meaning within the context of this Reliability Standard, negating the need for Footnote 2.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

Tri-State agrees with the additional comments provided by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

No additional comments at this time.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6

Answer	
Document Name	

Comment

“There are concerns about reliably modeling IBRs on the grid. With the vast amount of intermittent capacity being added each year, we are affecting the system in ways that are currently unpredictable which reduces reliability. A contributing factor to this is the vast amount of data that is expected to be stored and analyzed. Can the Standards Drafting Team explain the reasoning behind the need to store a large amount of data that will likely go unused? Data Centers create a huge draw on the electric grid so the need to retain this amount of data seems counterintuitive to improving the reliability of the grid. Would it be possible to systematically study the effects before allowing more resources to be added instead of requiring a post-mortem review?”

Likes 0	
Dislikes 0	

Response

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3

Answer	
Document Name	

Comment

SMEs responded with the folloing comments:

- “There are concerns about reliably modeling IBRs on the grid. With the vast amount of intermittent capacity being added each year, we are affecting the system in ways that are currently unpredictable which reduces reliability. A contributing factor to this is the vast amount of data that is expected to be stored and analyzed. Can the Standards Drafting Team explain the reasoning behind the need to store a large amount of data that will likely go unused? Data Centers create a huge draw on the electric grid so the need to retain this amount of data seems counterintuitive to improving the reliability of the grid. Would it be possible to systematically study the effects before allowing more resources to be added instead of requiring a post-mortem review?”

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	
Document Name	

Comment

NCPA is not voting on this proposal but has provided comments.

Likes 0	
Dislikes 0	

Response

Bill Zuretti - Electric Power Supply Association - 5

Answer	

Document Name	EPSA FINAL Comments on IBR Standards .pdf
Comment	
Likes 0	
Dislikes 0	
Response	
Rob Robertson - Leeward Renewable Energy - 5	
Answer	
Document Name	PRC-028 Aug 2024.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2021-04 Modifications to PRC-002 – Phase II | PRC-028-1
Comment Period Start Date:	7/22/2024
Comment Period End Date:	8/12/2024
Associated Ballot(s):	2021-04 Modifications to PRC-002 – Phase II Implementation Plan AB 4 OT 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 AB 4 ST

There were 60 sets of responses, including comments from approximately 135 different people from approximately 91 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 Manager of Standards Information, Nasheema Santos (via email) or at (404) 290-6796.

Questions

1. **Do you agree with the modifications made in PRC-028-1?**

2. **Do you agree with the Implementation Plan for revised PRC-028-1?**

3. **Do you agree the modifications made in PRC-028-1 are cost effective at unit level cost versus plant level cost compared to the benefit to reliability?**

4. **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
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,NPCC,RF,SERC,SPP RE,Texas RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Matt Goldberg	ISO New England	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Elizabeth Davis	PJM	2	RF
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF

Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Amber Skillern	East Kentucky	1	SERC

						Power Cooperative		
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
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
					Tyler Brun	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern	1	SERC

Company Services, Inc.						Company Services, Inc.		
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	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
					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
				David Kiguel	Independent	7	NPCC
				Joel Charlebois	AESI	7	NPCC
				Joshua London	Eversource Energy	1	NPCC
				Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
				Joel Charlebois	AESI	7	NPCC
				John Hastings	National Grid	1	NPCC
				Erin Wilson	NB Power	1	NPCC
				James Grant	NYISO	2	NPCC
				Michael Couchesne	ISO-NE	2	NPCC
				Kurtis Chong	IESO	2	NPCC
				Michele Pagano	Con Edison	4	NPCC
				Bendong Sun	Bruce Power	4	NPCC

					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the modifications made in PRC-028-1?	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While requiring recording all the fault codes and fault alarms as listed in R1.2 and R1.3 is certainly well-meaning, there may be disadvantages in requiring this breadth of data capturing and provision. Functional Entities (such as Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, and the Regional Entity) may not all equally benefit from receiving every fault code and fault alarm specified in R1.2 and R1.3. Fault codes and fault alarms differ across manufacturers and devices, and this is further complicated by the lack of standardization and consistent nomenclature in this area. Also, some entities may not be able to fully understand or draw proper conclusions from some of this data, which could lead to inconsistent and undesirable interpretation and application. Rather than requiring "all" the fault codes and alarms available, might it be worth considering for the standard to specify exactly which fault codes and alarms that the SDT believes would be beneficial?

AEP strongly recommends that the STD remove the requirement to capture all fault codes and alarms on IBR Units as SER data to +/- 100 millisecond from the standard and allow the GO to address IBR Unit performance issues as required under PRC-030.

PRC-029 requires the GO to ensure the design of IBR units meets the voltage and frequency ride through requirements or notify the applicable RC, BA and TO if the IBR is technically unable to meet those requirements. PRC-030 requires the GO to develop and execute a process to analyze Real Power change events including ride-through performance and implement corrective actions to address performance issues including applicable other GO IBR facilities.

Adding the requirement to capture all fault codes and alarms on IBR Units as SER data to +/- 100 millisecond back into this standard is unreasonable as it adds significant costs to the SER system and excessive administrative burden on the GO if an event occurs. Note that large IBR facilities have hundreds of IBR Units which would require the SER system to have thousands of SER data points. Is the intent of this requirement to have the TP, PC, TO, BA, RC, Regional Entity, or NERC determine the root cause of IBR Unit performance? If so, then why, as

PRC-030 clearly holds the GO responsible for performing this analysis. When an event occurs, the GO may be requested to submit DME data as proposed in PRC-028 while also having to address performance issues as required by PRC-030. Collecting SER data from every IBR Unit will be time consuming or require an expensive automated SER data collection system. The DME data for the MPT and collector bus should allow the TP, PC, TO, BA, RC, Regional Entity, or NERC to determine performance issues down to the IBR facility level and any corrective actions required on IBR Units would be address by the GO as required by PRC-030. AEP disagrees with the mid-ballot period removal of Transmission Owner from the list of Functional Entities. The TO may in some cases be the owner of the MPT and high side breakers.

Likes 0	
Dislikes 0	

Response
Thanks for your comment. It is understood that fault codes and alarms from IBR units may not be requested by the TP/PC/BA etc. However, availability of this data may help OEM and GO engineers to understand the event. There is also no standardization of fault codes/alarms at the IBR unit level across all OEMs and hence specific codes and alarms are not listed in the standard. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views from many stakeholders. The SDT recognizes the cost burden of this standard. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft. Also note that IBR units should already be capable to record the SER data required by this standard. No additional disturbance monitoring equipment should be necessary to record SER data from IBR units. The TO was removed from the list of functional entities to align with PRC-029 and PRC-030 standards. As industry learns more about TO's role and ownership of equipment within IBRs, these standards could be revisited and modified as necessary.
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	
Comment	

A) Duke Energy agrees with and supports the following NAGF comment:

1.b. Requirement R1.1:

i. NAGF members are still not certain that use of the term "collector bus(es)" includes feeder breakers and therefore are requesting that the requirement narrative be clarified to address this issue.

B) R1 Sections 1.2 & 1.3, 1.2.3 and 1.2.4, 1.3.3 & 1.3.4 require a mode status; this request is not a function of the recorders. In the technical rationale, please address this requirement or change standard to record voltage and frequency values instead of mode.

Likes 0	
Dislikes 0	
Response	

Thanks for your comment.

The collector bus itself does not include circuit breakers and any other equipment connected to it. Hence, R1 states that "circuit breakers associated with the main power transformer(s), collector bus(es), shunt static and dynamic reactive device(s),….."

The technical rationale includes additional information regarding fault codes, alarms, and ride-through mode status.

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

1. Based on the latest draft, the Standards Drafting Team (SDT) has removed the Transmission Owner from this Reliability Standard's applicability. Part 1.1 of Requirement R1 states a Generator Owner is required to retain sequence of event recording (SER) data for the circuit breaker positions associated with main power transformers, collector buses, shunt static and dynamic reactive devices, and AC-DC and DC-AC converters, if any, in case of VSC HVDC systems. Following the removal of the Transmission Owner, we believe the inclusion of circuit breaker positions for AC-DC and DC-AC converters is now misplaced and should also be removed.
2. Requirement R1 will require a Generator Owner to retain SER data. When applied to Parts 1.2 and 1.3, a Generator Owner is then required to perform a second action, which is to retain data for each individual IBR unit. The concept of the individual IBR unit was recently abandoned by the SDT in the previously proposed draft. We believe this is a reversal in the direction for Generator Owners to adopt this Reliability Standard. Nonetheless, we propose removing the phrases "shall be recorded" and "all" in these parts for clarity. We instead recommend rephrasing these parts to "…the following recorded data when triggered by ride-through operation or tripping of an IBR unit: fault codes, fault alarms, high and low voltage ride-through mode statuses, and high and low frequency ride-through mode statuses."
3. Part 1.3 allows for an exclusion to Generator Owners if the IBR Facility is incapable to record sequence of event data for each individual IBR unit. We believe the measure for this requirement should be expanded so Generator Owners can document this incapability as evidence.
4. Based on the latest draft, the SDT expanded the requirements of a Generator Owner to retain fault recording (FR) data for each collector feeder breaker. While data may exist, the purpose of the Protection Systems associated with each feeder breaker is to protect the collector bus from a Fault and the possibility of a failure within the feeder breaker. These Protection Systems use existing voltage and current sensing devices already on-site as Protection System Components. However, the SDT also proposes triggering the recording of FR data on each collector feeder breaker based on overfrequency and underfrequency events. The SDT assumes existing Protection Systems are capable of being reprogrammed to include this functionality. However, some microprocessor relays associated with each collector feeder breaker may not have such functionality available.
5. Part 3.2.3 identifies settings when fault recording devices are triggered to begin recording data. We believe each of the individual triggers currently listed should also have a statement identifying only if such capabilities exist. A similar statement should also be added to the measure for this requirement to support this as evidence.
6. Requirement R6 will require a Generator Owner to retain time synchronized data within a device clock accuracy of ± 1 milliseconds of Coordinated Universal Time (UTC). In this recently proposed draft, the SDT has added a requirement that each IBR unit's device clock accuracy must have its accuracy within ± 100 milliseconds of UTC. This new requirement was embedded within Part 6.2 as a separate sentence and suggests each IBR unit must be synchronized to a clock source. For existing facilities, this capability may not be possible. We further believe this approach opens a gap and data associated with IBR units would then be required to have a device clock accuracy of ± 1 milliseconds of UTC. We propose the following approach to revising this requirement. First, remove the phrase "all" in

reference to SER, FR, and dynamic disturbance recording (DDR) data in Requirement R6. Second, revise Part 6.2 to "Synchronized device clock accuracy within ± 100 milliseconds of UTC when applied on IBR unit recorded data or within ± 1 milliseconds of UTC."	
Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The TO was removed to align with PRC-029 and PRC-030 standards. In case of offshore wind plants connected to ac transmission lines and per the IBR definition, the IBR includes HVDC line as well as AC-DC and DC-AC converter stations. Hence, monitoring of circuit breakers associated of as such is still required. As industry learns more about TO's role and ownership of equipment within IBRs, these standards could be revisited and modified as necessary.

Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views from many stakeholders. The SDT recognizes the cost burden of this standard. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft. Also note that IBR units should already be capable to record the SER data required by this standard. No additional disturbance monitoring equipment should be necessary to record SER data from IBR units.

The measure for R1 is expanded to allow GOs to document incapability of IBR units to record SER data.

The SDT recognizes that upgrading of equipment may be necessary in some cases to record FR and DDR data as required by this standard.

It is not the intent to require IBR units to have a device clock accuracy of ± 1 milliseconds of UTC. Minor revisions are made to R6, Part 6.2 to clarify this.

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	No
Document Name	

Comment	
TransAlta supports the comment provided by AEP regarding the recording of all the fault codes and fault alarms as listed in R1.2 and R1.3.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to WEP's comments.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The *NAGF provides the following comments for consideration:* *a. Applicability Section 4.2.2 – recommend that the term "Non-BES Inverter-Based Resources" be revised to "Non-BES Inverter-Based Resource(s)" to be consistent with other IBR standards.* *b. Requirement R1.1:* *i. NAGF members are still not certain that use of the term "collector bus(es)" includes feeder breakers and therefore are requesting that the requirement narrative be clarified to address this issue.* *c. Requirement 3.2.1 – NAGF members have noted that existing IBR facilities do not have the capability to provide a fault recording data record length of 2 seconds as defined in this requirement.* d. *Requirement 6.2 – NAGF members have indicated that individual IBR units do not have the ability to meet the +- 100 millisecond accuracy threshold.*	
Likes 0	

Dislikes 0	
Response	

Thanks for your comment.

The collector bus itself does not include circuit breakers and any other equipment connected to it. Hence, R1 states that "circuit breakers associated with the main power transformer(s), collector bus(es), shunt static and dynamic reactive device(s),….."

The SDT recognizes that upgrading of or new equipment may be necessary to be able to record data as specified in this standard.

Alison MacKellar - Constellation – 5	
Answer	No
Document Name	
Comment	

This latest revision re-introduced the non-BES IBRs and FR per collector feeder which were removed from the previous version. The implementation costs for PRC-028-1 are still appreciably higher than PRC-002.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The non-BES IBRs were reintroduced to satisfy directive in FERC order 901. The criterion for non-BES IBRs is approved by NERC Board Of Trustees.

In lieu of requiring FR data from IBR units, the FR data from collector feeder breakers is required. The SDT reached this compromise considering opposing views of various stakeholders.

Megan Melham - Decatur Energy Center LLC – 5	
Answer	No
Document Name	
Comment	

Capital Power supports the NAGF's comments:

The NAGF provides the following comments for consideration:

a. Applicability Section 4.2.2 – recommend that the term “Non-BES Inverter-Based Resources” be revised to “Non-BES Inverter-Based Resource(s)” to be consistent with other IBR standards.

b. Requirement R1.1:

i. NAGF members are still not certain that use of the term “collector bus(es)” includes feeder breakers and therefore are requesting that the requirement narrative be clarified to address this issue.

c. Requirement 3.2.1 – NAGF members have noted that existing IBR facilities do not have the capability to provide a fault recording data record length of 2 seconds as defined in this requirement.

d. Requirement 6.2 – NAGF members have indicated that individual IBR units do not have the ability to meet the +- 100 millisecond accuracy threshold.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The collector bus itself does not include circuit breakers and any other equipment connected to it. Hence, R1 states that “circuit breakers associated with the main power transformer(s), collector bus(es), shunt static and dynamic reactive device(s),…..”

The SDT recognizes that upgrading of or new equipment may be necessary to be able to record data as specified in this standard.

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

R1.

For IBRs – the OEMs are responsible for **SER** data only. The question OEMs have been having is "*what is a ride through operation*", to define what triggers capturing a ride through event. Its an ambiguous term where p.u. parameters and time duration need to be explicitly defined to be set at the IBR.

{C}1.1   there is no clarity on data that needs to be collected. Do we collect all listed or a single source? This should be stated within the requirement.

Recommendation to remove 1.3 since the requirements are the same as 1.2 except for the timing of COD with respect to when the Standard becomes effective. Requirement 1.3 appears to be reactive in nature. This timing may be better addressed as part of the implementation plan.

R2

The standard does not provide clarity on if collector feeder data is needed from all units or specific units. It is important to note that information is only available on the high side, nothing on the low side.

Recommendation to remove footnote 3 as IBR unit is not a defined term found in the NERC Glossary of Terms.

R3

For DFRs in the substation – there was a change adding MV "collector breakers" to record fault reporting data. No project today or E&C best practices recommend 34.5KV fault reporting with 64 samples/cycle.

Need clarification on whether data should be only for high side, whether for anything that tripped, or for the entire event. Our recommendation would be to focus on the high side of GSU only. R6 IBRs must be time synchronized to +/- 100milliseconds which implies PTP or installing a GPS clock at each inverter. Recommend Footnote 4 revised to “interchange” not “exchange.”	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Additional content is added in the Technical Rationale document which may help in understanding context of IBR unit SER data requirement. The SDT, along with feedback from NERC staff, believes that R1.3 is appropriate to be part of a standard instead of incorporating it in the implementation plan. The standard requires FR data from each collector feeder breaker. In lieu of requiring FR data from IBR units, the FR data from collector feeder breakers is required. The SDT reached this compromise considering opposing views of various stakeholders. An effort was made to define IBR unit by the Project 2020-06 SDT, but the team moved forward with IBR definition only as it was anticipated that IBR unit definition may not be used by many standards. Hence, for the purposes of PRC-028 only, this SDT added a footnote to clarify this term. The SDT recognizes that in some cases upgrading of or new equipment may be necessary to meet the data recording requirements of this standard. Footnote 4 is revised as suggested.	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	

This latest revision re-introduced the non-BES IBRs and FR per collector feeder which were removed from the previous version. The implementation costs for PRC-028-1 are still appreciably higher than PRC-002.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The non-BES IBRs were reintroduced to satisfy directive in FERC order 901. The criteria for non-BES IBRs is approved by NERC Board of Trustees.

In lieu of requiring FR data from IBR units, the FR data from collector feeder breakers is required. The SDT reached this compromise considering opposing views of various stakeholders.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

R1.3:

This requirement must be more specific with use of word “if capable”. Consider providing a clear exemption.

R2.1.3, R2.2.3, and R3.2.3

The protective devices with FR capabilities cannot capture Real and Reactive quantities. These quantities are typically calculated by using captured voltage and current quantities. SDT should clarify and state if calculated P and Q values are acceptable. If calculated P & Q values are not acceptable, then this requirement will have to be satisfied by installing dedicated fault recorders which can be a substantial burden on cost and implementation plan.

R3:

While WEC Energy Group fully supports triggering FR at proposed locations, WEC has a concern with 2 seconds recording requirement and 64 samples per cycle recording rate.

Most of the older microprocessor based protective relays do not have 2 seconds recording capabilities. The DT recognized this as well in the Technical Rationale document *(“Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, can provide adequate fault data but are not capable of providing fault data in a single record with 120 continuous cycles total.”*). Note that microprocessor relays cannot record back to back events if the trigger is not active. This requirement, as currently written, will trigger costly upgrades. WEC suggest that SDT evaluates protective devices capabilities for most common relay manufacturers and reduces the recording requirement to 1 second.

Most of the older microprocessor based protective relays only have 4 or 8 samples/cycle sampling rate and do not have 64 samples per cycle recording rate capabilities. This requirement, as currently written, will trigger costly upgrades. WEC suggest that SDT evaluates protective devices capabilities for most common relay manufacturers and reduces the sampling rate below 64 samples per cycle.

These requirements seem to be more restrictive than PRC-002.

If recording and sampling requirement cannot be reduced, then existing FR equipment in commercial operation before the effective date of this standard should be exempted from 2 second recording requirement and 64 samples per cycle recording rate.

R3.1.3, R3.2.3, and R3.3.3:

SDT should determine pickups for the triggers. As currently written, entity could set pickups way too high or low and FR could never get recorded. For example, we can set 65Hz pickup for over-frequency. By the time we reach 65Hz, the event could be over.

R.6.2:

WEC Energy Group recommends that synchronized clock accuracy match PRC-002, which is +/- 2 milliseconds. An exception should be granted to IBR units in commercial operation before the effective date of this standard if synchronized signal at the IBR is not available or its accuracy cannot meet 100ms requirements. R7: WEC Energy Group suggests that R7 requirements match PRC-002 requirements.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The technical rationale includes additional detail regarding R1, Part 1.2 and 1.3, including some clarification for IBR units that are in commercial operation and meaning of "if capable" to record SER data. The Requirement R2 states "fault recording (FR) data to ***determine*** the following electrical quantities". The "determine" implies "calculated quantities are acceptable." The duration of FR recording is justified to capture IBR's response over few seconds after a fault is cleared. The SDT recognizes that in some cases upgrading of equipment or new equipment may be necessary to be able to record data as specified in this standard. The trigger pickups are intentionally not specified. This is consistent with PRC-002. The triggers may vary based on site location and interconnection. Synchronized clock accuracy requirement for plant level data is +/- 1 millisecond and reflects advances in technology since the publication of PRC-002. Considering challenges in achieving clock accuracy requirement, the higher tolerance is allowed for IBR units. The R7 is based on lengthy discussion among SDT members considering comments received from many stakeholders during previous ballots.	

Note that purpose of PRC-028 is very different from purpose of PRC-002.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO recommends that the STD remove the requirements R1.2 and R1.3, to capture all fault codes and alarms on IBR Units as SER and allow the GO to address IBR Unit performance issues as required under PRC-030.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views from many stakeholders. The SDT recognizes the cost burden of this standard. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft. Also note that IBR units should already be capable to record the SER data required by this standard. No additional disturbance monitoring equipment should be necessary to record SER data from IBR units.	
Scott Thompson - PNM Resources - 1,3,5 – WECC	
Answer	No
Document Name	
Comment	
Please consider the following: Define the term IBR Unit - rather than in footnotes	

Following the removal of the Transmission Owner, we believe the inclusion of circuit breaker positions for AC-DC and DC-AC converters is now misplaced and should also be removed. Clarifying the term “collector bus(es)” to include feeder breakers. Many IBR units do not have the ability to meet the +- 100 millisecond accuracy threshold, considerably higher than PRC-002.

Likes 0	
Dislikes 0	

Response
Thanks for your comment. An effort was made to define IBR unit by the Project 2020-06 SDT, but the team moved forward with IBR definition only as it was anticipated that IBR unit definition may not be used by many standards. Hence, for the purposes of PRC-028 only, this SDT added a footnote to clarify this term. Based on IBR definition, the HVDC line and associated AC-DC and DC-AC converters are part of IBR. Hence, recording of circuit breaker positions for AC-DC and DC-AC converters is required. The collector bus itself does not include circuit breakers and any other equipment connected to it. Hence, R1 states that “circuit breakers associated with the main power transformer(s)[1], collector bus(es), shunt static and dynamic reactive device(s),…..” Regarding synchronized device clock accuracy, the higher number means less accuracy. The plant level measurements are required to have accuracy within +/- 1 millisecond but recognizing challenges with IBR unit, the accuracy requirement is relaxed to within +/- 100 milliseconds.

[1] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for Inverter-Based Resources. In case of dedicated VSC HVDC system connecting to an Inverter-Based Resource, a transformer isolating the DC-AC converter from the transmission system is also considered a main power transformer.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
R1.2 and R1.3 can involve hundreds of data points for a large facility if “all fault” and “all alarm” codes are included for every IBR unit on a site. Southern Company requests the SDT to consider adding verbiage to limit monitoring requirements to a sample of the IBR units within a facility. What (who) determines criteria of “if capable” in R1.3? Southern Company requests the SDT to consider updating M1 to include documentation explaining the IBR unit is not capable of providing the data for recording. Industry may require clarification of the term “ride through mode status” in R1.2 and R1.3. Southern Company requests the SDT to consider providing the necessary clarification. Southern Company believes R7.2 needs to be changed back to 30 days.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Additional content is added in the technical rationale document to clarify that no additional recording equipment is needed to record IBR unit level SER data. Only SER data that is directly related to IBR unit tripping and ride-through operation are required. Measure M1 is revised as suggested. The timeline allowed in Requirement R7, Part 7.2 is a compromise based on many differing opinions from various stakeholders.	
Colin Chilcoat - Invenergy LLC - 5,6	

Answer	No
Document Name	
Comment	
In response to many industry comments regarding the burdens and equipment limitations involved with previously proposed IBR Unit level monitoring requirements, the SDT responded in the Consideration of Comments issued on May 31, 2024, stating, "the SDT has reviewed the NERC disturbance reports, consulted with manufacturers, and considered the burden to industry. The data requirements are addressed in the PRC-028 Technical Rationale. All individual unit requirements have been removed from the latest draft, and meeting these requirements should be less of an issue with equipment used to monitor at the plant level." In Draft 4, not only have the IBR Unit level monitoring requirements been reinserted, but they have also been expanded to include monitoring at every IBR Unit. This sudden reversal of course runs counter to the previous three rounds of industry comment, and the SDT's own responses to those comments. Can the SDT provide additional justification or comment on the reasoning behind this change of course?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views from many stakeholders. The SDT recognizes the cost burden of this standard. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft. Also note that IBR units should already be capable to record the SER data required by this standard. No additional disturbance monitoring equipment should be necessary to record SER data from IBR units.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	

In response to many industry comments regarding the burdens and equipment limitations involved with previously proposed IBR Unit level monitoring requirements, the SDT responded in the Consideration of Comments issued on May 31, 2024, stating, "the SDT has reviewed the NERC disturbance reports, consulted with manufacturers, and considered the burden to industry. The data requirements are addressed in the PRC-028 Technical Rationale. All individual unit requirements have been removed from the latest draft, and meeting these requirements should be less of an issue with equipment used to monitor at the plant level."

In Draft 4, not only have the IBR Unit level monitoring requirements been reinserted, but they have also been expanded to include monitoring at every IBR Unit. This sudden reversal of course runs counter to the previous three rounds of industry comment, and the SDT's own responses to those comments. Can the SDT provide additional justification or comment on the reasoning behind this change of course?

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views from many stakeholders. The SDT recognizes the cost burden of this standard. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft. Also note that IBR units should already be capable to record the SER data required by this standard. No additional disturbance monitoring equipment should be necessary to record SER data from IBR units.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024

Answer	No
Document Name	

Comment

In its June 14 comments, the ISO/RTO Council (IRC) Standards Review Committee (SRC) requested that inverter-level requirements be reinstated in PRC-028 and applied to all future IBR installations, at a minimum. The SRC provided numerous reasons for why the removal of these requirements is problematic and could impact reliability. The SRC understands from the SDT's consideration of this comment that the

IBR unit SER data requirement was a compromise in lieu of the FR data. However, the SRC is still concerned that the FR data is limited to what the SER would provide as recommended in NERC's September 2019 guideline.

The SRC has noted since the initial draft that the DDR installation requirements proposed in PRC-028 should be considered in meeting DDR coverage requirements of PRC-002. Even though the SDT cites an example where there is not any overlap of DDR coverage between the 2 standards, the SRC believes the standard needs to allow for considerations of system topography in certain areas today where there is significant IBR penetration and possible DDR coverage overlap. The SRC believes the 2 standards need to be able to reconcile the possibility of overlapping coverage Footnote, ISO NE does not support this portion of the response to Q1.

Parts 2.2 and 3.2 are new and require a GO to have FR data for Collector Feeder breakers. Without a clear definition of "Collector Feeder" it is unclear whether this will be applicable only to generators that are configured to directly energize a Collector Feeder as part of a distribution network or whether R3.2 would include any non-BES distribution facilities (such as those located within a plant)?

The SRC also believes that Requirement R1, Parts 1.2 and 1.3 should also apply to broader impacts, including momentary cessation or any other abnormal behavior during events, and should therefore be revised to read as follows.

1.2. For IBR units in commercial operation after the effective date of this standard,

the following data shall be recorded when triggered by ride-through operation,

tripping, or longer-term disturbance response and recovery of an IBR unit including.

1.2.1. All fault codes.

1.2.2. All fault alarms.

1.2.3. High and low voltage ride-through mode status.

1.2.4. High and low frequency ride-through mode status.

1.2.5 Momentary cessation

1.2.6 Other abnormal behavior during events

1.3. For IBR units in commercial operation before the effective date of this standard,

the following data shall be recorded, if capable, when triggered by ride-through operation, tripping, or longer-term disturbance response and recovery of an IBR unit including.

1.3.1. All fault codes.

1.3.2. All fault alarms.

1.3.3. High and low voltage ride-through mode status.

1.3.4. High and low frequency ride-through mode status.

1.3.5 Momentary cessation

1.3.6 Other abnormal behavior during events

Because the “IBR Unit” definition will not be moving forward, it appears each standard seeking to acquire IBR unit information, such as Parts 1.2 and 1.3, will need to define what IBR unit means within the standard. In the case of PRC-028, the SRC understands that footnote 2 serves this purpose, and asks that the drafting team confirm whether the SRC’s understanding is correct.

The SRC supports Parts 2.2 and 3.2 primarily as a starting point for gathering collector feeder breaker FR data in this version of the standard. The SRC believes there is potential for future expansion of these requirements if they are found to be inadequate in the course of investigating the root causes of IBR performance issues.

Part 6.2 currently reads, “Synchronized device clock accuracy within ± 1 milliseconds of UTC. The IBR units shall have synchronized device clock accuracy within ± 100 milliseconds of UTC.”

The SRC seeks clarification from the SDT as to why 100 milliseconds was chosen for Part 6.2 when IEEE uses 100 microseconds. Currently, there are Generator Interconnection Agreements that require 1 millisecond time synchronization for plant- and unit-level device clock accuracy. Many entities are considering adopting the IEEE requirements, so an explanation for this difference is critical.

Additionally, the SRC recommends that PRC-028 be revised to require recording of inverter-level oscillography. As demonstrated throughout the 2022 Odessa Disturbance report, it is evident that inverter-level oscillography is readily available and critical to proper event analysis in cases where individual inverters trip offline even though frequency and voltage at the plant level remain in the must-ride-through zone. This is a known issue where terminal voltages and frequency measurements can vary greatly from the plant-level measurements due to the collector system and step-up transformer designs. In many cases this oscillography is available but just needs to be enabled and adequate storage made available. Table 19 in Section 11 of IEEE 2800 already requires recording of such information at the IBR unit level as well. Such a requirement could be applied to new units and to existing units that already have that capability available and simply need to enable it.

NERC recommended the following in the 2022 Odessa disturbance report for the SDT to consider (emphasis added).

"Monitoring Data ERCOT and the GOs in the Texas Interconnection ***have extensive data*** that is ***critical for root cause analysis***. This ***data includes*** plant-level high resolution oscillography data, plant SCADA data, and ***inverter-level*** sequence of events recording (e.g., fault codes) and ***oscillography data***. ***These types of measurements should be standard across industry for the purposes of event analysis and reducing the risk to plant performance***. The IRPS submitted a SAR, ***and Project 2021-04 is working on enhancements to PRC-002-2 to ensure this type of data is available at BES resources."***

Footnote: MISO is a party to these comments but does not support the comments in response to Q1.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The SDT reached a compromise considering opposing views from various stakeholders and required SER data from all IBR units. In lieu of requiring FR data from sample of or all IBR units, the standard required FR data from all collector feeder breakers.

The collector Feeder is a feeder that connects one or more IBR unit step-up transformer with the collector bus. The technical rationale provides some examples. As industry learns more about IBRs and their configuration, the standard could be revisited and modified as necessary based on future learnings.

Note that momentary cessation is inherently a part of ride-through mode. Clarify statement is added in the technical rationale.

An effort was made to define IBR unit by the Project 2020-06 SDT, but the team moved forward with IBR definition only as it was anticipated that IBR unit definition may not be used by many standards. Hence, for the purposes of PRC-028 only, this SDT added a footnote to clarify this term.

The SDT has heard from many stakeholders regarding the time synchronization accuracy requirement. The GPS clock typically exists at the plant level and signal of this GPS clock is shared with various equipment within the facility. Recognizing the latency and ability of commonly used protocol to transmit signal from plant level GPS clock to many IBR units within the plant, the SDT increased tolerance for time synchronization accuracy to ± 100 milliseconds. The recordings synchronized to higher time accuracy makes it easy to align data from various sources to perform event analysis, however, data not synchronized to higher time accuracy is still useful and is expected to serve the purpose.

The SDT recognizes that IBR unit level FR data might be more valuable than FR data recorded at the collector feeder breaker. However, considering opposing views of various stakeholders, cost burden, project timeline, etc., a compromise is made and in this first version of the standard, the collector feeder breaker FR data is required. Based on future learnings with implementation of this standard, future events, etc., the standard could be revised as necessary.

Kennedy Meier - Electric Reliability Council of Texas, Inc. – 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to IRC SRC’s comments.	
Jennifer Neville - Western Area Power Administration - 1,6	

Answer	No
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comments.	
Steven Rueckert - Western Electricity Coordinating Council – 10	
Answer	No
Document Name	
Comment	
As written, Requirement R1 brings ambiguity with the use of "IBR unit" with the footnote definition. Additionally, what is a "ride-through operation"? For example- As written, the entity will need to record all aspect/Parts of R1.2 and R1.3 assuming the location failed the Ride-through definition or tripped offline. The discussion will be is it "all fault codes" of the inverter, converter, wind turbine generator, or high voltage direct current converter individually (as applicable)? Or something else? Requirement 1 Part 1.2 and Part 1.3 (including all sub Parts for both)- Capitalize "ride-through" as it is a defined term in another related Project.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The definition of IBR unit for inclusion in NERC glossary is not moving forward, hence, the SDT decided to include footnote 3 to clarify IBR unit for purposes of this standard.	

The “ride-through operation” is when voltage or frequency deviates from nominal beyond certain threshold. Thresholds for voltage and frequency are set in inverter that declares ride-through operation. This is well understood in the industry and IBR unit OEMs. The requirement is to record whenever IBR unit enters a ride-through operation and not only when it fails to ride-through system disturbance. Additional explanation is added to the Technical Rationale document. The “ride-through” definition is not approved yet, hence, not included in this standard at this time.

Kenisha Webber - Entergy - NA - Not Applicable – SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
No comments are submitted.	
Rob Robertson - Leeward Renewable Energy – 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
No comments are submitted.	

Robert Follini - Avista - Avista Corporation – 3	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy finds no objection to this standards' proposed draft.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Donna Wood - Tri-State G and T Association, Inc. – 1	
Answer	Yes
Document Name	

Comment	
Tri-State agrees with the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Marcus Bortman - APS - Arizona Public Service Co. – 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ruchi Shah - AES - AES Corporation – 5	
Answer	Yes
Document Name	
Comment	
AES CE does not agree that SER data at every IBR Unit is necessary to meet the objectives of the Standard. Past revisions contained more reasonable solutions such as SER data at the end of each feeder. We believe this middle solution will have a significant positive impact on	

system reliability, while adding this data at every single IBR Unit offers only an incremental improvement in ability to analyze system disturbances at a huge burden to GOs.	
Likes 0	
Dislikes 0	
Response	
Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views from many stakeholders. The SDT recognizes the cost burden of this standard. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to PRC-028-1 (Draft 4).	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	
Comment	

Ameren agrees with and supports EEI's comments.

Likes 0	
Dislikes 0	

Response
Thanks for your comment. See response to EEI's comments.
Selene Willis - Edison International - Southern California Edison Company – 5

Answer	Yes
Document Name	

Comment
"Please see EEI Comments"

Likes 0	
Dislikes 0	

Response
Thanks for your comment. See response to EEI's comments.
Bobbi Welch - Midcontinent ISO, Inc. – 2

Answer	Yes
Document Name	

Comment
MISO supports the requirements (Parts 1.2 and 1.3) for IBR unit data. We also observe that, as the "IBR Unit" definition will not be moving forward, it appears each standard seeking to acquire IBR unit information, will need to define what IBR unit means within the standard. In the case of PRC-028, this is footnote 3. Is that correct?

MISO supports Parts 2.2 and 3.2 as a starting point to gather collector feeder breaker FR data. That said, we also support the potential for future expansion of these requirements if they are found to be inadequate when investigating the root cause of IBR performance issues.

Part 6.2. “Synchronized device clock accuracy within ± 1 milliseconds of UTC. The IBR units shall have synchronized device clock accuracy within ± ***100 milliseconds*** of UTC.”

Regarding Part 6.2., MISO is requesting clarification as to why the SDT chose 100 milliseconds when IEEE uses 100 microseconds. Currently, MISO’s Generator Interconnection Agreement requires 1 millisecond time synchronization for plant and unit level device clock accuracy. As MISO is considering adopting the IEEE requirements, please explain the reason for the differential.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

Correct, the IBR unit definition for inclusion in NERC Glossary is not moving forward currently. Because the PRC-028 requires IBR unit level SER data to be recorded, the footnote 3 is added to clarify IBR unit for purposes of this standard.

Thanks for your support for collector feeder level data in lieu of IBR unit level data.

The SDT has heard from many stakeholders regarding the time synchronization accuracy requirement. The GPS clock typically exists at the plant level and signal of this GPS clock is shared with various equipment within the facility. Recognizing the latency and ability of commonly used protocol to transmit signal from plant level GPS clock to many IBR units within the plant, the SDT increased tolerance for time synchronization accuracy to ± 100 milliseconds. The recordings synchronized to higher time accuracy makes it easy to align data from various sources to perform event analysis, however, data not synchronized to higher time accuracy is still useful and is expected to serve the purpose.

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation – 3

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Bruce Walkup - Arkansas Electric Cooperative Corporation – 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 – SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Michael Johnson - Michael Johnson On Behalf of: 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	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Casey Jones - Berkshire Hathaway - NV Energy - 5 – WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Evergy - 1,3,5,6 – MRO	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Anna Martinson - MRO - 1,2,3,4,5,6 – MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Hillary Creurer - Allete - Minnesota Power, Inc. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Carver Powers - Utility Services, Inc. – 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,NPCC,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Marty Hostler - Northern California Power Agency – 4	
Answer	

Document Name	
Comment	
We do not disagree with modifications that have been made and we do not object to FERC order 901. However, we do not believe this standard will improve reliability as the GO/GOP IBR entites would have to share data with (BAs, PAs, RCs, TOPs) only if they ask for said data. And those entities do not have any obligations to do anything with the data which GO/GOP IBRs would be required to provided them. Consequently, we are unclear as to how GO/GOP IBRs that are required to procure and install a bunch of recording data and share recordings with entities, only if those entities ask for it, will do anything to improve reliability. As written this proposal looks like an expense to GO/GOPs with no reliability benefits. All entities that GO/GOP IBRs are required to provide data to need to have requirements within this standard version detailing what they are to do with said data in order to improve reliability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Various NERC disturbance reports published over last five years have suggested that there is a lack of data to analyze system disturbances. It is expected entities on Transmission side will be involved in data gathering from IBRs when performing event analysis. The data recorded as required by this standard is expected to serve as evidence for upcoming IBR ride-through standard PRC-029. One of the purposes of this standard is to record data that may be used for model validation, standards for which are expected to come along in near future.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	

NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EPSA's comments.	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EPSA's comments.	

2. Do you agree with the Implementation Plan for revised PRC-028-1?	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	

PRC-029 and PRC-030 hinge on the Implementation Plan (IP) for PRC-028. The inconsistent approach (“design”/”operation” aspects of Requirements in PRC-029/030 IPs) and use of “commercial operations date” in PRC-028 IP does not provide clarity. The DTs did not define what the design and operation aspects of PRC-030 are so compliance monitoring will be difficult if at all achievable until ALL parts of PRC-028 are applicable (essentially 2030). The use of commercial operation date is inconsistent with reliability and differs across the United States. There are no compliance evaluations that can be done for non-BES IBRs until after Jan 1, 2030.

For the following Implementation Plan requirement, the DT needs to be extremely clear that the 15 calendar months is ONLY applicable to the “effective date of the standard” portion of the phrase and not the “commercial operation date”:

“For non-BES Inverter-Based Resources in commercial operation after May 2026: Entities shall comply with Requirements R1 through R7 within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later. “

Does the DT confirm that interpretation of the phrase is correct? Effective date of standard plus 15 calendar months OR commercial operation date whichever is later is the correct way to read that phrase.

Most implemtation plans are effective on the first day of a quarter. If May is actually the desired month, the IP should not simply say “May 2026” it should be specivic such as May 1, May 15, or May 31, 2026.

Having a process for extension of compliance embedded within an Implementation Plan is not conducive or supportive to reliability. As written, this will be an administrative effort with NO defined timeline in sight and no process to support it. The ERO Enterprise should utilize the current processes in place. That is, if the entity, who has had years to be ready, is noncompliant they self-report the issue and follow the mitigation process. Putting this process in place requires a second set of books for compliance determination and status. The Implementation Plan (and the dependence of other Implementation Plans) does not set any expectation for IBRs to be compliant by any set date and does not support FERC’s intention of having Standards applied to IBRs no later than 2030. What happens if the entity does not

provide information or provides information that is found to be incorrect and the CEA does not approve the extension? What happens if the entity does not supply the extension request in less time than "required" (i.e., "no later than three months prior to the compliance date")? FERC recently ruled on cold weather standards regarding Corrective Action Plans being too long. The timing for these exemptions is non-existent and provides a compliance loophole that can be easily exploited by entities not addressing reliability in an effective manner. Those entities invested in reliability should be working towards implementation of these Requirements now. Unfortunately, the system is experiencing entities that are more interested in the bottom line versus reliability. Implementation Plans are not enforceable but set dates for enforcement based on the Standard Requirement language. No extension process should be considered. The electrical ecosystem has been experiencing IBR issues for a decade already and the risk this technology has exposed can not continue by allowing extensions. This again begs for a timeline diagram for the implementation of these 3 Standards (PRC-028/029/030) so that everyone knows the exact expectations for compliance dates.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The PRC-028 implementation plan is designed considering engineering, procuring, and commissioning of DME to record stated SER, FR, and DDR data. The SDT agrees that the PRC-029 and PRC-030 implementation plans need to coordinate with the PRC-028 implementation plan, where the data recorded under PRC-028 is needed for compliance with PRC-029 and PRC-030. For BES IBRs, the implementation plan provides an example to clarify meaning of "within 15 calendar months following the effective date of the standard or the commercial operation date, whichever is later". The SDT agrees with the interpretation that timeline is the effective date plus 15 calendar month OR the commercial operation date, whichever is later. "May 2026" is replaced with "May 1, 2026". The framework to seek extension from the Compliance Enforcement Authority is based on feedback from NERC staff. The PRC-028 may require engineering, procuring, and commissioning of new DME at majority of plant. To account for issues outside of Entity's control, the SDT in good faith provided a framework to seek extension from the compliance enforcement authority.	

Jennifer Neville - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	
Please consider the following: Clarification regarding the Compliance Enforcement Authority (CAE) process to be used for evaluating a PRC-028 compliance date extension request. DME equipment installation time needs to be considered during implementation.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT discussed time needed to engineer, procure, and commission DME at IBR plants in development of the implementation plan. The framework to request extension is included as well. The CEA process seeking extension was developed with feedback from NERC staff. The SDT is unable to provide more details of the process.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO agrees with the majority of the implementation plan but still has concerns with the “15 calendar months following the effective date of the standard” requirement for inverter-based resources entering commercial operation after the effective date, and believes that more time is needed to properly budget, modify designs and procure equipment for projects already under development. NIPSCO proposes modifying the following language: For inverter-based resources entering commercial operation after the effective date: Entities shall comply with Requirements R1 through R7 within “36 calendar months following the effective date of the standard or by" the commercial operation date, whichever is later.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT considered time needed to engineer, procure, and commission DME at the plants under development and concludes that “15 calendar months following the effective date of the standard” is an adequate time.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
Unless WEC Energy Group comments listed in #1 above are addressed, the implementation plan will be too short.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to comment by WEC Energy Group.	
Hillary Creurer - Allete - Minnesota Power, Inc. – 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comments.	
Kimberly Turco - Constellation – 6	
Answer	No
Document Name	
Comment	
Although the PRC-028 Implementation Plan mirrors PRC-002-2 Implementation Plan, PRC-028 requires all BES IBRs and many non-BES IBRs to have DME installed. If the GO has a large IBR fleet, numerous DME installations would be required with a demanding project schedule. With the large amount of DME required to be installed per PRC-028, OEMs might not be able to provide GOs with a timely supply of DME equipment. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Your concern is valid. The implementation plan offers a framework to request extension from the compliance enforcement authority to address situation noted in comment.	
Richard Vendetti - NextEra Energy – 5	
Answer	No
Document Name	
Comment	
For the implementation plan, we recommend focusing on those sites with a COD post the Standard becoming effective. Having an implementation for units with a COD prior to the Standard becoming effective does not appear consistent with implementation of other Standards, being retroactive, and will create undue burden to IBR owners who will need to perform rework on existing sites, as vendors have already indicated the equipment to meet compliance will not be available until 2026. In addition, we note the duration to implement has become an issue as the timeline has shifted by one year and the deadline to fully implement remains by 2030. NextEra recommends an implementation of 2032 to be fully compliant, providing reasonable time for the first 50% and the remainder of the sites. While we appreciate the Implementation Plan's note recognizing the potential supply chain issues and the potential for registered entities to address delays outside of their control, we do not think addressing these known issues as part of Compliance and Enforcement is the most effective for both industry and the ERO. As currently written, not only will we have further supply chain issues generated from the timeline reduction and the retroactive nature of requirement 1.3. but additional administrative burden post Standards development.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The FERC order 901 directive requires inclusion of IBRs in commercial operation before the effective date of this standard. The implementation plan recognizes that there may be challenges in installing DME at existing plants. To address those, the implementation plan offers a framework to seek extension from the compliance enforcement authority.	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
PRC-002 allowed ~6 years for implementation. It appears that PRC-028 will allow ~3.5 years for non-BES IBR owners to meet compliance following the registration deadline and ~4.5 years assuming an effective date of 7/1/25 for BES owners. If non-BES or BES owners have multiple existing facilities to update for compliance this may be difficult. Consider giving a similar time window of ~6 years to meet compliance. It seems larger facilities meeting this standard would be more beneficial than the numerous non-BES facilities.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The implementation plan is designed around the timeline required by the FERC order 901. To account for circumstances beyond the entity’s control that may hinder installation of DME in a specified timeframe, the implementation plan includes a framework to seek extension from the compliance enforcement authority.	
Alison MacKellar - Constellation – 5	
Answer	No
Document Name	
Comment	
Although the PRC-028 Implementation Plan mirrors PRC-002-2 Implementation Plan, PRC-028 requires all BES IBRs and many non-BES IBRs to have DME installed. If the GO has a large IBR fleet, numerous DME installations would be required with a demanding project schedule. With the large amount of DME required to be installed per PRC-028, OEMs might not be able to provide GOs with a timely supply of DME equipment. Alison Mackellar on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Your concern is valid. The implementation plan offers a framework to request extension from the compliance enforcement authority to address situation noted in comment.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	No
Document Name	
Comment	
TransAlta supports the comments provided by Radian Generation regarding requesting an extension. TransAlta supports the comments provided by Berkshire Hathaway regarding implementation timelines.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to comments submitted by Radian Generation and Berkshire Hathaway.	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
We believe the Process for Requesting an Extension from Compliance Data has embedded inefficiencies that could place undue burdens on Generator Owners. As Generator Owners patiently await on an approval for an extension from their Compliance Enforcement Authority (CEA), even providing additional follow-up information requested from that CEA in a timely matter, the compliance burden still lies with the Generator Owner until such an extension is finally granted. Industry continues to see some CEAs struggle with addressing their backlogs for	

handling potential non-compliance of existing registered entities. Some of these registered entities have not even received a response from their CEA in years. We believe some accountable on the ERO Enterprise should be included within this Implementation Plan, whether under the Requesting an Extension Process or as a general consideration. This includes the development of a standard template that would be used across the ERO Enterprise for Generator Owners to complete when making an extension request. This template would identify all the information that is required to make the extension upfront. A completed template by the Generator Owners then would not impede the request because of insufficient information. The process should also have some timeline constraints, such that a request is never left unanswered. This time could be reasonable to account for impacts on CEA resources, such as six months and at which time, the CEA is required to provide an update to the requesting Generator Owner on its review of the request. Failure to provide an update, or continuously extending this period for the CEA to process the request, would automatically imply the request for extension has been granted to the Generator Owner. NERC should also oversee the requesting process to ensure consistency is evenly applied by each CEA.	
Likes 0	
Dislikes 0	
Response	
NERC anticipates that an ERO Enterprise process will be developed, similar to the TPL-007 CAP Extension Request Review Process that is included as Appendix C in the 2024 Periodic Data Submittal Schedule. This ERO Enterprise process could address items such as information needed as part of the extension request, roles and responsibilities, and timelines.	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	No
Document Name	
Comment	
PRC-002 allowed ~6 years for implementation. It appears that PRC-028 will allow ~3.5 years for non-BES IBR owners to meet compliance following the registration deadline and ~4.5 years assuming an effective date of 7/1/25 for BES owners. If non-BES or BES owners have multiple existing facilities to update for compliance this may be difficult. Consider giving a similar time window of ~6 years to meet compliance. It seems larger facilities meeting this standard would be more beneficial than the numerous non-BES facilities.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The implementation plan is designed around the timeline required by the FERC order 901. To account for circumstances beyond the entity's control that may hinder installation of DME in a specified timeframe, the implementation plan includes a framework to seek extension from the compliance enforcement authority.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD agrees with the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to comment submitted by MRO NSRF.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP supports the implementation schedule for R1-R7 for units in commercial operation prior to the effective date but requests the same implementation schedule be used for R8 as the DME system most likely will not have been installed by the effective date of R8. If the intent is to have a CAP to identify the targeted compliance date, this would create excessive administrative burden on the GO.	

The example provided for compliance of IBR facilities entering commercial operation *after* the effective date does not make sense as stated. AEP recommends that the effective date for IBR facilities entering commercial operation after the effective date be required to comply with the standard within three (3) calendar years of the effective date of Reliability Standard PRC-028-1 to align with the requirements for existing IBR facilities. For the reasons stated above, the compliance date for R8 for Non-BES IBR facilities should be the same as R1-R7.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The requirement R8 applies only if the DME is installed. The compliance date for R8 could be independent of compliance date for R1-R7. The SDT considered time needed to engineer, procure, and commission DME at the plants under development and concludes that "15 calendar months following the effective date of the standard" is an adequate time.	
Donna Wood - Tri-State G and T Association, Inc. – 1	
Answer	No
Document Name	
Comment	
Tri-State agrees with the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to comment by MRO NSRF.	
Rob Robertson - Leeward Renewable Energy - 5	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
No comments are provided.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
No comments are provided.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
No comments are provided.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"Please see EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Please provide further clarification regarding the Compliance Enforcement Authority (CAE) process to be used for evaluating a PRC-028 compliance date extension request, including the proper mechanism for submitting a request and timelines involved in the evaluation process.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The framework to request extension from the Compliance Enforcement Authority was developed with feedback from NERC staff. The SDT is unable to provide more details of the process.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	

Answer	Yes
Document Name	
Comment	
The NAGF requests further clarification regarding the Compliance Enforcement Authority (CAE) process to be used for evaluating a PRC-028 compliance date extension request.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The framework to request extension from the Compliance Enforcement Authority was developed with feedback from NERC staff. The SDT is unable to provide more details of the process.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy finds no objection to this standards' proposed draft.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,NPCC,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates 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	
The SDT appreciates your support.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Michael Johnson - Michael Johnson On Behalf of: 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	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your support.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your support.	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EPSA comments.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	

Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EPSA's comment.	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	
This implemention plan appears more reasonable then the PRC-29 and PRC-30's six month implementation plans. We believe the implementation plans for those two standards should be the same as PRC-28.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

3. Do you agree the modifications made in PRC-028-1 are cost effective at unit level cost versus plant level cost compared to the benefit to reliability?	
Marty Hostler - Northern California Power Agency – 4	
Answer	No
Document Name	
Comment	
The SDT has not provided any cost or expected reliability indices improvement estimates. Consequently, it is impossible for entities to determine if this proposal is cost effective, or not; or to what extent, this proposal will improve reliability. Reliability standards should not be added or changed until the SDT provides said information so that Registered Entities can make educated determinations related to the cost and benefits of reliability standard modifications or new proposals. Basically, what we are being asked to do is to analyze the cost and reliability benefits this proposal would provide without any data. And, ironically GO/GOP IBR Entities are being asked to spend money to procure and install a bunch of devices to record data and/or to perform new activities that may, or may not, improve reliability. And if they do improve reliability, we don't have any idea if the reliability benefits are worth the cost. Electricity customers Nationwide will have the rates raised and there is no justification or hard evidence related to the improved reliability increase magnitude; i.e. no cost/benefit justification to provide customers as to why then rates will be increased.	
Likes 1	Utility Services, Inc., 4, Powers Carver
Dislikes 0	
Response	
Thanks for your comment. The SDT acknowledges your concerns. The SDT has addressed the scope of the SAR and FERC order 901 directives while considering cost impact. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation – 3	

Answer	No
Document Name	
Comment	
SMEs responded with the following comments: • "The modifications will create undue burden on the utilities for likely little improvement to reliability. The study of IBRs on the grid should have taken place before the unprecedented addition of these intermittent resources without enough data to judge the impact to reliability."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT acknowledges your concerns. The SDT has addressed the scope of the SAR and FERC order 901 directives while considering cost impact. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	
"The modifications will create undue burden on the utilities for likely little improvement to reliability. The study of IBRs on the grid should have taken place before the unprecedented addition of these intermittent resources without enough data to judge the impact to reliability."	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT acknowledges your concerns. The SDT has addressed the scope of the SAR and FERC order 901 directives while considering cost impact. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers.	
Donna Wood - Tri-State G and T Association, Inc. – 1	
Answer	No
Document Name	
Comment	
Tri-State agrees with the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Thomas Foltz - AEP – 5	
Answer	No
Document Name	
Comment	
As stated previously, adding the requirement to capture all fault codes and alarms on IBR Units as SER data to +/- 100 millisecond back into this standard is unreasonable, as it adds significant costs to the SER system and excessive administrative burden on the GO if an event occurs.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views. The SDT recognizes the cost burden of this standard. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
This standard makes sense for new inverter-based resources (IBRs). However, for the legacy IBRs the reliability benefits do not justify the costs. The costs to design, purchase and install the required equipment for IBRs that are 10 years old or older, does not make sense if the facility has limited or no controls compared to the modern IBR equipment being installed today. PRC-028-1 provides a limited exemption in Requirement R1 for the data to be collected, but the data could be useless if the IBR's legacy controls place hard limitations on the ability of the IBR to actually ride-through a system disturbance.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The various disturbance reports published by NERC over last five years or so justifies monitoring on legacy plants. The intent is to analyze plants performance and use recorded data for model validation. Additionally, the FERC order 901 directs that legacy plants are included in the applicability of this standard.	

Casey Jones - Berkshire Hathaway - NV Energy - 5 – WECC	
Answer	No
Document Name	
Comment	
PRC-028-1 will result in costs that are not in-line with the reliability benefits provided. These costs are not only for the design and implementation of the monitoring but also for new communications infrastructure for legacy locations or compliance related staff to monitor, track and maintain compliance where it was not required before. For those owners that stream PMU data this standard could add significant communications costs to upgrade older facilities. The reliability benefit of installing, maintaining, and operating monitoring capabilities on existing equipment does not justify the cost.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The various disturbance reports published by NERC over last five years or so justifies monitoring on legacy plants. The intent is to analyze plants performance and use recorded data for model validation. Additionally, the FERC order 901 directs that legacy plants are included in the applicability of this standard.	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
1. We believe the recent modifications to reintroduce the individual IBR unit to the proposed NERC Reliability Standard provide very little benefit to reliability. The information available at the IBR collector bus level and main power transformers are more than sufficient to determine how a IBR facility performed following a Disturbance. We question how operational entities would incorporate fault code and fault alarm data into their post-event analyses for improving BPS reliability. Generator Operators and Generator Owners, who are more familiar with fault codes and fault alarms, use such data for troubleshooting a localized issue detected within the IBR facility and to generate more immediate corrective actions in response.	

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views. The SDT recognizes the cost burden of this standard.

The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft.

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	No
Document Name	

Comment

TransAlta supports the comments provided by SMUD and BANC regarding legacy IBRs. Furthermore, TransAlta does not believe the standard adequately addresses paragraph 86 from FERC Order 901, "to consider the burdens of generators collecting and providing data, while assuring that Bulk-Power System operators and planners have the data they need for accurate disturbance monitoring and analysis."

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT acknowledges your concerns. The SDT has addressed the scope of the SAR and FERC order 901 directives while considering cost impact. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers.

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Evergy - 1,3,5,6 – MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Ruchi Shah - AES - AES Corporation – 5	
Answer	No
Document Name	
Comment	
AES CE believes this is not a cost effective approach to meet FERC Order 901. The requirement for SER data at every IBR Unit offers marginal benefit to reliability as compared to having SER data at the end of every feeder while incurring significant additional costs. AES CE recommends that the SDT leverage the expertise of Project Finance SMEs at the entities to understand the feasibility of implementing this new Standard, and the potential impacts to reliability that these additional costs could incur.	
Likes 0	
Dislikes 0	
Response	

The SDT acknowledges your concerns. The SDT has addressed the scope of the SAR and FERC order 901 directives while considering cost impact. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views. The SDT recognizes the cost burden of this standard. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Including non-BES IBRs for PRC-028-1 could present additional financial difficulties that might cause some GOs to consider other options. Due to the expenses of NERC Registry and PRC-028 requirements, non-BES IBR facilities could possibly be shut-down rather than meet the upcoming NERC requirements. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The FERC order 901 directs to include non-BES IBRs in the applicability of this standard.	
Anna Martinson - MRO - 1,2,3,4,5,6 – MRO	
Answer	No
Document Name	
Comment	
PRC-028-1 will result in costs that are not in-line with the reliability benefits provided. These costs are not only for the design and implementation of the monitoring but also for new communications infrastructure for legacy locations or compliance related staff to monitor, track and maintain compliance where it was not required before. For those owners that stream PMU data this standard could add significant communications costs to upgrade older facilities. The reliability benefit of installing, maintaining, and operating monitoring capabilities on existing equipment does not justify the cost. However, MRO NSRF does agree that the requiring monitoring capabilities on new equipment moving forward may be a cost-effective method to assist in addressing the issues set forth in the SAR and NERC Reports.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The purpose of PRC-028 is to record data necessary to evaluate and analyze performance of IBR plants. The recorded data is expected to be used as evidence for PRC-029 standard as well as for purposes of IBR plant model validation. The inclusion of non-BES IBRs as well as IBRs in commercial operation is required by directives in FERC order 901.	
Megan Melham - Decatur Energy Center LLC – 5	
Answer	No
Document Name	
Comment	
Capital Power will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Including non-BES IBRs for PRC-028-1 could present additional financial difficulties that might cause some GOs to consider other options. Due to the expenses of NERC Registry and PRC-028 requirements, non-BES IBR facilities could possibly be shut-down rather than meet the upcoming NERC requirements. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The FERC order 901 directs to include non-BES IBRs in the applicability of this standard.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
Feeder requirements under 3.2 are not necessary on smaller NON- BES sites. Can this requirement be updated to be applicable to only larger BES PV sites only?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The FR data from collector feeder breaker is required in lieu of FR data from IBR unit level data. There is no justification to exempt non-BES IBRs from this requirement.	
Hillary Creurer - Allete - Minnesota Power, Inc. – 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comments.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group does not agree that these modifications are cost effective compared to the benefit to reliability. As currently written, the Standard will trigger costly upgrades, especially to wind IBRs which were not identified as troubled equipment during the past IBR disturbances. To make it more cost effective, exceptions must be provided for certain equipment already in service.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT acknowledges your concerns. The SDT has addressed the scope of the SAR and FERC order 901 directives while considering cost impact. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Adding the requirements to capture all fault codes and alarms on IBR Units as SER data is unreasonable, as it adds significant costs and excessive administrative burden on the GO if an event occurs.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views. The SDT recognizes the cost burden of this standard. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
There are concerns about cost effectiveness if the entity is required to purchase hardware in order to reach the level of data recording suggested. If the entity is only required to update software, then the suggested updates appear cost-effective. We recommend incorporating an exception process for smaller entities who do not have the ability to configure existing equipment to gather the requested level of data recording.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT acknowledges your concerns. The SDT has addressed the scope of the SAR and FERC order 901 directives while considering cost impact. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers.	

Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	
The high cost of outfitting existing IBRs to comply outweighs the reliability gained.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT acknowledges your concerns. The SDT has addressed the scope of the SAR and FERC order 901 directives while considering cost impact. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company believes the modifications made to PRC-028-1 for legacy IBRs are **not** cost effective at unit level cost versus plant level cost compared to the benefit to reliability due to R1.3 inclusion.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views. The SDT recognizes the cost burden of this standard. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
The reversal of course in Draft 4 to require IBR Unit level monitoring at every IBR Unit imposes significant costs on entities without a commensurate benefit to reliability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views. The SDT recognizes the cost burden of this standard. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No

Document Name	
Comment	
The reversal of course in Draft 4 to require IBR Unit level monitoring at every IBR Unit imposes significant costs on entities without a commensurate benefit to reliability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Adding a requirement to record SER data for IBR units is a compromise that the SDT reached considering opposing views. The SDT recognizes the cost burden of this standard. The SDT developed requirements in this standard while balancing the need for monitoring data for IBR performance evaluation and model validation and cost of installing the DME. One example of this is that the FR data requirements are moved from IBR unit terminals to collector feeder breakers. To evaluate IBR's performance during system disturbances, some data from IBR units is necessary. As the FR data requirement is moved to collector feeder breakers, the SER data requirement from IBR units was reintroduced in the last draft.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments: ACES agrees with the approach taken by the SDT to create a new Standard to specifically address inverter-based resources; however, we disagree with making this new standard inclusive of all BES inverter-based resources regardless of risk to the BPS.	

In the opinion of ACES, a blanket approach requiring every IBR to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which inverter-based resources pose the biggest risk to the BPS, and where disturbance monitoring and reporting would provide the most benefit to the BPS, before selectively adding such capabilities.

We believe that a risk-based approach is the best and only truly cost-effective option for all applicable IBRs, we believe that this is especially true for existing IBRs. In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach for IBRs as is done in PRC-002-5 for synchronous generating resources.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

Please note that the purpose of PRC-028 is very different from purpose of PRC-002. The PRC-002 requires disturbance monitoring equipment at appropriate locations on the BES to help analyze wide-spread system disturbances. Hence, criteria in PRC-002 to identify locations where SER, FR, and DDR data is required is appropriate. The purpose of PRC-028 is to gather data to analyze performance of each IBR as well as use recorded data to validate models of IBRs.

Monitoring of all BES and non-BES IBRs is also one of the directives in the FERC order 901.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,NPCC,SERC,RF, Group Name ACES Collaborators

Answer	No
Document Name	

Comment

ACES agrees with the approach taken by the SDT to create a new Standard to specifically address inverter-based resources; however, we disagree with making this new standard inclusive of all BES inverter-based resources **regardless of risk** to the BPS.

In the opinion of ACES, a blanket approach requiring every IBR to install SER, FR, and/or DDR capabilities is overly gratuitous. We believe that the industry's finite resources would best be spent by first ascertaining which inverter-based resources pose the biggest risk to the BPS, and where disturbance monitoring and reporting would provide the most benefit to the BPS, before selectively adding such capabilities. We believe that a risk-based approach is the best and only truly cost-effective option for all applicable IBRs, we believe that this is especially true for existing IBRs. In summary, it is our recommendation that PRC-028-1 take a similar risk-based approach for IBRs as is done in PRC-002-5 for synchronous generating resources.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please note that the purpose of PRC-028 is very different from purpose of PRC-002. The PRC-002 requires disturbance monitoring equipment at appropriate locations on the BES to help analyze wide-spread system disturbances. Hence, criteria in PRC-002 to identify locations where SER, FR, and DDR data is required is appropriate. The purpose of PRC-028 is to gather data to analyze performance of each IBR as well as use recorded data to validate models of IBRs. Monitoring of all BES and non-BES IBRs is also one of the directives in the FERC order 901.	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
No comments are provided.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
No comments are provided.	
Rob Robertson - Leeward Renewable Energy - 5	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
No comments are provided.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
At this time, FirstEnergy finds no issue with the cost effectiveness toward the scope of this standard	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"Please see EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI’s comments.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
Cannot comment on cost effectiveness	

Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the draft standard.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the draft standard.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy will not submit a response to the cost effectiveness of the proposed changes.	
Likes 0	
Dislikes 0	
Response	

Thanks for taking time to review the draft standard.	
Michael Johnson - Michael Johnson On Behalf of: 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 does not have any comments as to the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the draft standard.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EPSA’s comment.	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	

Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EPSA's comments.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	
Document Name	
Comment	
Ameren does not have any additional comments on the cost effectiveness of this project.	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the draft standard.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	

No comment on the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the draft standard.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review the draft standard.	

4. Provide any additional comments for the standard drafting team to consider, if desired.

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Elevate appreciates the opportunity to comment on the draft NERC standards, particularly those pertaining to future IBR NERC Reliability Standards, and FERC Order No. 901 directives.

Elevate continues to strongly encourage NERC to reconsider adoption of IEEE 2800-2022. The unwillingness to adopt IEEE 2800-2022 by NERC is leading to entirely duplicative efforts that are not serving any additional value as compared to the work conducted in the IEEE 2800-2022 developments. It does not appear that a holistic approach and strategy is being taken to meet the FERC Order No. 901 directives, which is leading to very low ballot scores, significant rework, and misalignment with industry recommended practices.

Elevate strongly recommends a single NERC standard that adopts IEEE 2800-2022 in a uniform and consistent manner. NERC can also issue a reliability guideline or implementation guidance that supports industry implementation of the standard. Rather than recreate parts of IEEE 2800-2022 inconsistently over multiple different standards, Elevate recommends a singular standard for BPS-connected IBR capability and performance requirements related to IEEE 2800-2022. Additional NERC standards can be developed where needed in situations where they are not covered directly with IEEE 2800-2022 (e.g., NERC PRC-030).

While improvements have been made in this latest draft of the NERC PRC-028 standard, this standard is duplicative with IEEE 2800-2022 Clause 11 yet the latest draft of the standard is still missing some of the monitoring aspects covered in the IEEE 2800 standard, including power quality monitoring data and IBR unit FR/DDR data (and additional fault code types). The 2021 Odessa Disturbance report and the NERC IBR Reliability Guideline document both give a recommendation to include FR/DDR data on some IBR units on the collector busses at IBR plants, but currently the draft PRC-028 standard has no FR/DDR requirement for IBR units. This PRC-028-1 standard and other NERC IBR-focused standards should be conforming to/matching the IEEE 2800 standard.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The scope of this SAR is to specify disturbance monitoring requirements. This SDT has reviewed and build upon the monitoring requirements from the IEEE Std 2800-2022. In few instances, the SDT has intentional deviated from requirements in IEEE Std 2800 because requirements in IEEE 2800 may be impractical (e.g., time synchronization requirements, sampling rate and associated time duration of recording, etc.).

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	
Document Name	

Comment

PRC-028 R1 is using “IBR unit” versus IBR and provides a “definition” in the footnote 3 (only footnoted once but used several time in Requirement). Why complicate the issue with a definition in a footnote that would not be needed if using IBR only? That lacks consistency with PRC-029 and PRC-030 (which are inconsistent between each other as well). The use of commercial operation is ambiguous. Different entities may have a different definition of "commercial operation." Suggest clarification of what commercial operation is. Suggest something to the effect of IBRs must have these installed prior to first synch. Entities will have to maintain and provide ALL commercial operating dates for all IBRs.

The VSLs as written will require an extent of condition (entity will have to supply ALL applicable “Elements” and /or electrical quantities to determine severity level if a single issue is found with a sample.)

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The PRC-028 requires SER data from IBR units as well as plant level SER, FR, and DDR data at plant level (IBR). The PRC-029 and PRC-030 are plant level standards, hence, uses IBR only. As noted in a footnote, IBR unit is part of IBR. It is important to include a footnote explaining a meaning of IBR unit.

A footnote is added to clarify meaning of commercial operation. The VSLs in PRC-028 are similar to VSLs in PRC-002.
Jennifer Neville - Western Area Power Administration - 1,6

Answer	
Document Name	
Comment	
Support MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. – 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to IRC SRC's comment.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	

Answer	
Document Name	
Comment	
Given the reliance on electronic communications for compliance such as the Secure Evidence Locker, the SRC notes that it seems inappropriate to allow for hard-copy documentation, e.g. M1: The Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1 This also seems contradictory to the more specific data format requirements contained elsewhere in the standard, such as in Parts 7.3 and 7.4, and the SRC requests that the SDT consider revising M1. 7.3. SER data shall be provided in ASCII Comma Separated Value (CSV) format following Attachment 1. 7.4 FR data shall be provided either in CSV format with appropriate headers or in electronic files that are formatted…	
Likes 0	
Dislikes 0	
Response	
The measure in M1 and other similar measures in the standard are consistent with the PRC-002 standard. In cases where there is no recorded data to show as evidence, an entity is allowed to show evidence of data recording capability using one-line diagrams showing design, recording equipment configuration and manual etc., which could be hard copy.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	
Document Name	
Comment	
Exelon agrees with the EEI, Footnote 2 should be deleted from the final draft.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The PRC-028 has a requirement to record SER data for IBR units. The footnote 2 explains meaning of IBR unit as definition of IBR unit does not exist anywhere else.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,NPCC,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
ACES Member EKPC had the following additional comment: "DDR data for all BES and NON-BES IBRs is a large burden. If the Standards Drafting Team finds it untenable to take a risk-based approach for all PRC-028-1 Requirements (similar to PRC-002-4), then we recommend that PRC-028-1 Requirement R4 and R5 have exclusive applicability based on a risk-based analysis performed by the Reliability Coordinator." Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please note that the purpose of PRC-028 is very different from purpose of PRC-002. The PRC-002 requires disturbance monitoring equipment at appropriate locations on the BES to help analyze wide-spread system disturbances. Hence, criteria in PRC-002 to identify locations where SER, FR, and DDR data is required is appropriate. The purpose of PRC-028 is to gather data to analyze performance of each IBR as well as use recorded data to validate models of IBRs.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. – 1	
Answer	

Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review and comment.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	
R1.2.1, R1.2.2, R1.3.1, and **R1.3.2** are far too broad as currently drafted and must be amended to target specific categories of fault codes that the SDT deems relevant to the analysis of BES disturbances. Depending on the OEM, there may be thousands of fault codes, a vast majority of which would be entirely irrelevant to the purpose of analyzing BES disturbances. **R6.2** should be amended to include "if capable." Invenergy thanks the drafting team for the opportunity to provide feedback.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	

Additional content is added in the technical rationale to clarify that fault codes ad alarms associated with IBR unit tripping or entering ride-through operations are required to be recorded.

The time synchronization is required for all recorded data. The technical rationale explains a need for this. However, recognizing challenges in synchronizing device clock for IBR units, a higher tolerance is permitted for IBR unit clock accuracy.

Colin Chilcoat - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	

Invenergy thanks the drafting team for the opportunity to provide feedback.

R1.2.1, R1.2.2, R1.3.1, and **R1.3.2** are far too broad as currently drafted and must be amended to target specific categories of fault codes that the SDT deems relevant to the analysis of BES disturbances. Depending on the OEM, there may be thousands of fault codes, a vast majority of which would be entirely irrelevant to the purpose of analyzing BES disturbances.

R6.2 should be amended to include "if capable."

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

Additional content is added in the technical rationale to clarify that fault codes ad alarms associated with IBR unit tripping or entering ride-through operations are required to be recorded.

The time synchronization is required for all recorded data. The technical rationale explains a need for this. However, recognizing challenges in synchronizing device clock for IBR units, a higher tolerance is permitted for IBR unit clock accuracy.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC RSC supports the project.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company does not agree with the language in PRC-028, R8 requiring a Corrective Action Plan to be submitted to the Regional Entity. If at any time a Regional Entity desires to review a TO's or GO's Corrective Action Plans, they have the authority to request them. Requiring the Corrective Action Plans to be submitted to the Regional Entity with no requirement for action by the Regional Entity is purely administrative and does nothing to improve the reliability of the Bulk Electric System. Further, the timely development and implementation of a Corrective Action Plan needed to repair equipment can be thoroughly examined during an audit engagement. This same reasoning applies to PRC-002, R12 and is also recommended to be removed.	
Likes 0	
Dislikes 0	

Response	
The requirement R8 in PRC-028 is like requirement R12 in PRC-002. The PRC-002 standard in effect (and since revision in 2014 under the project 2007-11) already require entities to develop a Corrective Action Plan and submit it to the Regional Entity. The PRC-028 follows the precedent set in PRC-002 standard.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to NPCC RSC's comments.	
Carver Powers - Utility Services, Inc. – 4	
Answer	
Document Name	
Comment	
1. Based on the purpose statement, this standard appears to be creating double jeopardy. If a non-compliance occurs with PRC-028, the entity is presumably non-compliant with Modeling standards in addition to PRC-029. However, it seems that the intent of the standard is similar to PRC-002: to capture adequate data to facilitate analysis of BES System Disturbances. 2. We recommend that the DT recreate the purpose statement of PRC-028 to align with the PRC-002 purpose statement. We believe the intent of the standard is to gather the necessary event data to analyze system disturbances. PRC-002 focuses on the TO (and some large generation facilities that meet the threshold in R5) gathering the appropriate data and doing it in a manner that is consistent so it can be	

analyzed in a more efficient manner when a large system disturbance occurs. PRC-028 suggests that IBR's, regardless of size, have significant event recording capabilities. For the smaller IBR facilities that will inevitably be applicable to this standard, this data may not be useful at all. If this standard requires upgrades to hardware or additional hardware to meet the recording capabilities, this may not be commercially viable for these smaller entities that may not have any relevant data for analysis. Therefore, if care is not taken when further development of this standard occurs, the majority of these Requirements would end up being administrative in nature and not be beneficial for improved reliability of the BES. 3. In our entity's review of this project, we are voting in the affirmative. We understand and appreciate that this project addresses important considerations for reliability and security responsiveness. However, we also recognize that this project in its current form presents compliance and performance risks that remain unresolved. While affirmatively supporting this project to address the immediate regulatory assignments tied to FERC Order 901, NERC and the ERO must continue a constructive dialog with industry beyond this vote to truly optimize the impacts of this project on reliability, sustainability, and affordability. We encourage NERC to permit extending the SDT team and project to offer prospective enhancements or revisions to satisfy these compliance and performance risks.

Likes 0	
Dislikes 0	

Response
Thanks for your comment. The PRC-028 requires certain type of data to be recorded. If the data is not recorded then data cannot be used as evidence for PRC-029 standard. However, that does not mean that an entity is out of compliance with the PRC-029 standard. Please note that the purpose of PRC-028 is very different from purpose of PRC-002. The PRC-002 requires disturbance monitoring equipment at appropriate locations on the BES to help analyze wide-spread system disturbances. Hence, criteria in PRC-002 to identify locations where SER, FR, and DDR data is required is appropriate. The purpose of PRC-028 is to gather data to analyze performance of each IBR as well as use recorded data to validate models of IBRs. The SDT appreciates your support for this standard.
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI's comments. Ameren offers the following for consideration: **R1**: Ameren recommends that the drafting team clarify what is meant by "fault codes" and "fault alarms" as applied to the standard for R1. **R2**: The standards drafting team requires real and reactive power expressed on a three-phase basis. However, during a fault, these values would be zero. Ameren recommends that Volts and Amps are the only necessary data collected during a fault event. **R3**, Ameren proposes 30 to 60 cycles per event with 2 cycles of pre-event data at 32 samples per cycle, which can be accomplished with most modern relays. The values for output recording rate and synchronized device clock accuracy should match PRC-002. Additionally, the number of days in R7.1 and R7.2 should also match PRC-002.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Additional content is added in the technical rationale to clarify what is meant by fault code and fault alarms. The real and reactive power would be zero only in cases of close-in faults. The standard requires measured quantities to “determine” real and reactive power, which inherently means that voltage and current recordings are needed. The purpose of PRC-028 is very different from purpose of PRC-002. The sampling rate, recording duration, etc., is justified based on IBR technology and to align with purpose of the standard.	
Romel Aquino - Edison International - Southern California Edison Company – 3	

Answer	
Document Name	EEI Near Final Draft Comments _ Project 2021-04 PRC-002_028 Draft 4 _ Rev 0a __ 8_06_2024 (002).docx
Comment	
See comments submitted by the Edison Electric Institute in the attached file	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to EEI's comments.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI offers the following non-substantive change to PRC-028-1 for consideration: • Footnote 2 should be deleted. "IBR unit" is no longer used in the proposed definition of IBR and therefore has no meaning within the context of this Reliability Standard, negating the need for Footnote 2.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The PRC-028 has a requirement to record SER data for IBR units. The footnote 2 explains meaning of IBR unit as definition of IBR unit does not exist anywhere else.	
Hillary Creurer - Allete - Minnesota Power, Inc. – 1	
Answer	

Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF's comment.	
Kimberly Turco - Constellation – 6	
Answer	
Document Name	
Comment	
The cost and burden of the proposed PRC-028 requirements are not believed justified by the reliability benefits it would provide. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The various NERC disturbance reports over last five years have shown a need for this standard. Further, the proposed standard is also needed to meet FERC order 901 directives.	
Anna Martinson - MRO - 1,2,3,4,5,6 – MRO	
Answer	
Document Name	

Comment	
MRO NSRF is concerned about Regional Entities' ability to objectively and correctly evaluate requests for Seeking Extensions to Compliance Dates. MRO NSRF recommends that the SDT create clear and auditable criteria that if met, allow for the extension of compliance dates. GOs and TOs would submit notification to the Regional Entity that they will require an extension to the compliance dates, based on the met criteria. The Regional Entities' role would be to ensure that the proper criteria are indicated by the GO or TO to allow for an extension of compliance dates, rather than make subjective decisions on approval of requests. This would also eliminate concerns about differences between regions in allowing for extensions. MRO NSRF does not agree with the language in R8 of PRC-028 and R12 of PRC-002, requiring a Corrective Action Plan to be submitted to the Regional Entity. If at any time a Regional Entity desires to review a TO's or GO's Corrective Action Plans, they have the authority to request them. Simply requiring the Corrective Action Plans to be submitted to the Regional Entity with no requirement for the Regional Entity to do something with them is purely and administrative and does nothing to improve the reliability of the Bulk Electric System. While MRO NSRF supports much of this proposed standard, MRO NSRF does not agree with requiring the retrofitting of monitoring equipment on existing individual inverter based generating resources as included by I4, MRO NSRF does however believe that forward looking design standard addressing new installations would be reasonable.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. NERC anticipates that an ERO Enterprise process will be developed, similar to the TPL-007 CAP Extension Request Review Process that is included as Appendix C in the 2024 Periodic Data Submittal Schedule. This ERO Enterprise process could address items such as information needed as part of the extension request, roles and responsibilities, and timelines. The requirement R8 in PRC-028 is like requirement R12 in PRC-002. The PRC-002 standard in effect (and since revision in 2014 under the project 2007-11) already require entities to develop a Corrective Action Plan and submit it to the Regional Entity. The PRC-028 follows the precedent set in PRC-002 standard.	

The inclusion of IBRs already in commercial operation is required by FERC order 901 directives.	
Alison MacKellar - Constellation – 5	
Answer	
Document Name	
Comment	
The cost and burden of the proposed PRC-028 requirements are not believed justified by the reliability benefits it would provide. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The various NERC disturbance reports over last five years have a shown a need for this standard. Further, the proposed standard is also needed to meet FERC order 901 directives.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no additional comments.	
Likes 0	
Dislikes 0	
Response	

Thanks for taking time to review and submit comments.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) – 1	
Answer	
Document Name	
Comment	
TAL understands that the committee was following previous precedent of the 20MVA or greater facilities; however, we believe this standard will create undue hardship on utilities who will be required to meet this standard. 20MVA seems like a low threshold for the size of IBRs. TAL believes the impact of IBRs as small as 20 MVA seems minimal to the integrity of the BES.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The FERC order 901 directs that non-BES IBRs are included in the applicability of new proposed standards. Based on FERC directive, NERC developed the non-BES IBR criteria.	
Ruchi Shah - AES - AES Corporation – 5	
Answer	
Document Name	
Comment	
Many existing devices used for fault recording (SEL-351 for example) cannot meet the 2.0 second duration in R3.1.1. A duration of 1.0 second would better align with equipment capabilities. Perhaps the clause could be written that all new equipment should have the 2.0 second duration capability while existing equipment has requirements in-line with the capabilities of the equipment installed over the past few years.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT understands that the equipment may need to be upgraded to record data for a specified duration. The 2-second recording duration is based on need to understand plants performance during and immediately after the system disturbance.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Evergy - 1,3,5,6 – MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. See response to MRO NSRF’s comment.	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
No comments are provided.	

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
1. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review and submit comments.	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
1. Purpose: we suggest harmonizing the usage of the term Inverter Based Resources and its acronym across the projects 2021-04, 202-02 and 2023-03. We suggest adding the acronym IBR in brackets after the capitalized term Inverter Based Resources, and to refer to IBR throughout the document. 2. We suggest that the drafting team modify section 4.2.2 to reflect the changes that were made to PRC-029-1 in Project 2020-02 and PRC-030-1 in project 2023-02. We suggest the following wording: “The Elements associated with (1) Bulk Electric System (BES) IBRs and (2) Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.”	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. It is not clear why the "elements associated with" is included in PRC-029. Perhaps it will be removed as standard is being revised at this time. There is no need to include "elements associated with" in PRC-028.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	
Document Name	
Comment	

The language in **Section 4, Applicability** does not match the language used in the latest proposed versions of PRC-029-1 and PRC-030-1.

The drafting team should remove the words "that owns equipment as identified in section 4.2" in Section 4.1.1. and ensure that the Section 4, Applicability language match the language in PRC-029-1 and PRC-030-1. The final, preferred language for Section 4, Applicability is shown below. This change is non-substantive and could be made in the final ballot.

The existing language in PRC-028-1 is as follows:

4.1. Functional Entities:

4.1.1. Generator Owner ***that owns equipment as identified in section 4.2***

4.2. Facilities:

4.2.1 BES Inverter-Based Resources

4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

SMUD’s preferred language in PRC-028-1 Section 4, Applicability is as follows:

4.1 Functional Entities:

4.1.1. Generator Owner

4.2. Facilities:

4.2.1 BES Inverter-Based Resources

4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. 4.1.1 is revised as suggested.

Michael Johnson - Michael Johnson On Behalf of: 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

None are being provided.

Likes 0	
Dislikes 0	

Response

Thanks for your support.
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	

Duke Energy agrees with and supports the following EEI comment:

EEI offers the following non-substantive change to PRC-028-1 for consideration:

•   Footnote 2 should be deleted. “IBR unit” is no longer used in the proposed definition of IBR and therefore has no meaning within the context of this Reliability Standard, negating the need for Footnote 2.

Likes 0	
Dislikes 0	

Response
Thanks for your comment. The PRC-028 has a requirement to record SER data for IBR units. The footnote 2 explains meaning of IBR unit as definition of IBR unit does not exist anywhere else.
Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	
Comment	

AZPS supports the following comment submitted by EEI on behalf of its members:

Footnote 2 should be deleted. “IBR unit” is no longer used in the proposed definition of IBR and therefore has no meaning within the context of this Reliability Standard, negating the need for Footnote 2.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The PRC-028 has a requirement to record SER data for IBR units. The footnote 2 explains meaning of IBR unit as definition of IBR unit does not exist anywhere else.

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

Tri-State agrees with the additional comments provided by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. See response to MRO NSRF’s comment.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

No additional comments at this time.

Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
No comments are provided.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	
Document Name	
Comment	
"There are concerns about reliably modeling IBRs on the grid. With the vast amount of intermittent capacity being added each year, we are affecting the system in ways that are currently unpredictable which reduces reliability. A contributing factor to this is the vast amount of data that is expected to be stored and analyzed. Can the Standards Drafting Team explain the reasoning behind the need to store a large amount of data that will likely go unused? Data Centers create a huge draw on the electric grid so the need to retain this amount of data seems counterintuitive to improving the reliability of the grid. Would it be possible to systematically study the effects before allowing more resources to be added instead of requiring a post-mortem review?"	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The several NERC disturbance reports over last five years have shown that IBR's performance during system disturbances is far from ideal. For event analysis, model validation, etc., the specified data in PRC-028 is necessary.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	
Document Name	
Comment	
SMEs responded with the folloing comments: • "There are concerns about reliably modeling IBRs on the grid. With the vast amount of intermittent capacity being added each year, we are affecting the system in ways that are currently unpredictable which reduces reliability. A contributing factor to this is the vast amount of data that is expected to be stored and analyzed. Can the Standards Drafting Team explain the reasoning behind the need to store a large amount of data that will likely go unused? Data Centers create a huge draw on the electric grid so the need to retain this amount of data seems counterintuitive to improving the reliability of the grid. Would it be possible to systematically study the effects before allowing more resources to be added instead of requiring a post-mortem review?"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The several NERC disturbance reports over last five years have shown that IBR's performance during system disturbances is far from ideal. For event analysis, model validation, etc., the specified data in PRC-028 is necessary.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
No comments are provided.	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	
NCPA is not voting on this proposal but has provided comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review and provide comments.	
Bill Zuretti - Electric Power Supply Association - 5	
Answer	
Document Name	EPSA FINAL Comments on IBR Standards .pdf
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. Comments are not specific to PRC-028 standard.	
Rob Robertson - Leeward Renewable Energy - 5	
Answer	
Document Name	PRC-028 Aug 2024.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Your comments are consistent with previously submitted comments. The FERC order 901 directives require that standard applies to non-BES IBRs and IBRs already in commercial operation before the effective date of this standard. The SDT is aware of cost burden of installing DME to record data as required by this standard. The SDT has tried to balance directives of FERC order 901, need of recorded data for performance evaluation and model validation, cost burden etc. while developing this standard. The implementation plan also allows for sufficient time within a timeframe permitted by the FERC order 901 directives. The purpose of PRC-028 is very different from purpose of PRC-002.	

Reminder

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II |PRC-028-1

Additional Ballots and Non-binding Poll Open through August 12, 2024

Now Available

Additional ballots for **PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-based Resources** and implementation plan, as well as the non-binding poll of the associated Violation Risk Factors and Violation Severity Levels, are open through **8 p.m. Eastern, Monday, August 12, 2024**.

This will be the last opportunity for NERC to ballot this project through traditional mechanisms. The Board may take requisite action during the August 2024 Board of Trustees meeting to ensure directives are met.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

To assist industry in this upcoming ballot period, NERC has released a Milestone 2 Summary that provides high-level overview of the current state of the associated projects and their interrelationships. The drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

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.

Note: Votes cast in previous ballots will not carry over to additional ballots. It is the responsibility of the registered voter in the ballot pools to place votes again. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *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 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 2021-04 Modifications to PRC-002 observer list” in the Description Box.

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UPDATED

Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II

Formal Comment Period Open through August 12, 2024

Now Available

A formal comment period for **PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-based Resources** is open through **8 p.m. Eastern, Monday, August 12, 2024**. The drafting team decided to remove "**4.1.1. Transmission Owner that owns equipment as identified in section 4.2**" from the **Applicability** and all of the Transmission Owner referenced in the Requirements of Standard PRC-028-1.

This will be the last opportunity for NERC to ballot these projects through traditional mechanisms. The Board may take requisite action during the August 2024 Board of Trustees meeting to ensure directives are met.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* Docket No. RM22-12-000 *on October 19, 2023.*

To assist industry in this upcoming comment and ballot period, NERC has released a Milestone 2 Summary that provides high-level overview of the current state of the associated projects and their interrelationships. The drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Note: PRC-002-5 passed the recent additional ballot (conducted June 5-15, 2024). The drafting team will be moving this standard to a final ballot when the PRC-028-1 ballots open (August 2-12, 2024) as only non-substantive revision(s) were made.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact **ballotadmin@nerc.net** to assist with the removal of any duplicate registrations.

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.

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Next Steps

Additional ballots for the standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 2 – 12, 2024**.

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 2021-04 Modifications to PRC-002 observer list” in the Description Box.

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Standards Announcement

Project 2021-04 Modifications to PRC-002 – Phase II
PRC-028-1

Formal Comment Period Open through August 12, 2024

Now Available

A formal comment period for **PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources** is open through **8 p.m. Eastern, Monday, August 12, 2024**.

This will be the last opportunity for NERC to ballot these projects through traditional mechanisms. The Board may take requisite action during the August 2024 Board of Trustees meeting to ensure directives are met.

The Standards Committee approved waivers to the Standard Processes Manual at their December 2023 meeting. These waivers were sought by NERC Standards staff for reduced formal comment and ballot periods. This will assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 901. *FERC Order 901 was issued under* **Docket No. RM22-12-000** *on October 19, 2023.*

To assist industry in this upcoming comment and ballot period, NERC has released a **Milestone 2 Summary** that provides high-level overview of the current state of the associated projects and their interrelationships. The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Note: PRC-002-5 passed the recent additional ballot (conducted June 5-15, 2024). The drafting team will be moving this standard to a final ballot when the PRC-028-1 ballots open (August 2-12, 2024) as only non-substantive revision(s) were made.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

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Next Steps

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Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 AB 4 ST
Voting Start Date: 8/2/2024 12:01:00 AM
Voting End Date: 8/12/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 235
Total Ballot Pool: 270
Quorum: 87.04
Quorum Established Date: 8/12/2024 3:20:04 PM
Weighted Segment Value: 80.7

Actions

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	72	1	39	0.813	9	0.188	0	17	7
Segment: 2	8	0.8	6	0.6	2	0.2	0	0	0
Segment: 3	59	1	40	0.816	9	0.184	0	4	6
Segment: 4	14	1	9	0.9	1	0.1	0	2	2
Segment: 5	68	1	33	0.717	13	0.283	0	10	12
Segment: 6	42	1	23	0.719	9	0.281	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: 10	6	0.5	5	0.5	0	0	0	0	1
Totals:	270	6.4	156	5.165	43	1.235	0	36	35

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
					Comments

3	WEC Energy Group, Inc.	Christine Kane		Negative	Submitted
1	National Grid USA	Michael Jones		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Stephen Sines	None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	AEP	Leshel Hutchings		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
6	AEP	Mathew Miller		Negative	Comments

					Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	None	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Third-Party Comments
3	Evergy	Marcus Moor		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Tyler Schwendiman		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Abstain	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A

1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
1	Manitoba Hydro	Nazra Gladu	Jay Sethi	None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A

2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
5	Leeward Renewable Energy	Rob Robertson		Negative	Comments Submitted
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	Richard Machado		Negative	Third-Party Comments
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments

					Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Glen Pruitt		None	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2021-04 Modifications to PRC-002 – Phase II Implementation Plan AB 4 OT
Voting Start Date: 8/2/2024 12:01:00 AM
Voting End Date: 8/12/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 233
Total Ballot Pool: 274
Quorum: 85.04
Quorum Established Date: 8/12/2024 3:34:58 PM
Weighted Segment Value: 84.55

Actions

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	74	1	40	0.851	7	0.149	0	16	11
Segment: 2	7	0.7	7	0.7	0	0	0	0	0
Segment: 3	60	1	42	0.84	8	0.16	0	4	6
Segment: 4	14	1	9	0.9	1	0.1	0	2	2
Segment: 5	68	1	35	0.778	10	0.222	0	10	13
Segment: 6	44	1	25	0.758	8	0.242	0	3	8
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: 10	6	0.5	4	0.4	1	0.1	0	0	1
Totals:	274	6.3	163	5.326	35	0.974	0	35	41

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A

1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
1	Duke Energy	Katherine Street	Ellese Murphy	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Affirmative	N/A

6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Stephen Sines	None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	AEP	Leshel Hutchings		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
6	AEP	Mathew Miller		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted

3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	None	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Evergy	Marcus Moor		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Tyler Schwendiman		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Abstain	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
1	Manitoba Hydro	Nazra Gladu	Jay Sethi	None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A

3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
					Third-Party

3	New York Power Authority	Richard Machado		Negative	Comments
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Glen Pruitt		None	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
6	Great River Energy	Brian Meloy		None	N/A
1	Los Angeles Department of Water and	faranak sarbaz		None	N/A

	Power			
3	City Utilities of Springfield, Missouri	Jessica Morrissey	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith	None	N/A

[redacted]

Ballot Results

Ballot Name: 2021-04 Modifications to PRC-002 – Phase II PRC-028-1 | Non-Binding Poll AB 4 NB
Voting Start Date: 8/2/2024 12:01:00 AM
Voting End Date: 8/12/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 226
Total Ballot Pool: 261
Quorum: 86.59
Quorum Established Date: 8/12/2024 3:24:35 PM
Weighted Segment Value: 77.51

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	69	1	33	0.805	8	0.195	22	6
Segment: 2	7	0.4	3	0.3	1	0.1	3	0
Segment: 3	57	1	34	0.791	9	0.209	8	6
Segment: 4	14	1	9	0.9	1	0.1	2	2
Segment: 5	66	1	27	0.73	10	0.27	16	13
Segment: 6	41	1	20	0.69	9	0.31	5	7
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment:	0	0	0	0	0	0	0	0

9								
Segment: 10	6	0.4	4	0.4	0	0	1	1
Totals:	261	5.9	131	4.715	38	1.185	57	35

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A

1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments

					Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	AEP	Leshel Hutchings		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
6	AEP	Mathew Miller		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A

5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Evergy	Marcus Moor		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
10	ReliabilityFirst	Tyler Schwendiman		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Abstain	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted

1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
	Edison International - Southern California				

6	Edison Company	Stephanie Kenny		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Austin Energy	Michael Dillard		Abstain	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A

3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	JEA	John Babik		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	New York Power Authority	Richard Machado		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A

1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
5	TransAlta Corporation	Ashley Scheelar	Adam Burlock	Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Glen Pruitt		None	N/A
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A

Exhibit H

Standard Drafting Team Roster

SAR Drafting Team Roster

Project 2021-04 Modifications to PRC-002-2

	Name	Entity
Chair	Manish Patel	Southern Company Services
Vice Chair	Christopher Milan	NewFields
Members	Bret Garner Burford	American Electric Power
	Don Burkart	Consolidated Edison of New York
	Tracy Kealy	Bonneville Power Administration
	Amy Key	MidAmerican Energy Company
	Terry Volkmann	Volkmann Consulting
	Jacob Magee	Transmission Asset Management
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